BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California.	R.04-01-025

JOINT COMMENTS OF EL PASO NATURAL GAS COMPANY AND MOJAVE PIPELINE COMPANY

In accordance with ordering paragraph 7 of the referenced Order Instituting Rulemaking ("OIR"), El Paso Natural Gas Company ("EPNG") and Mojave Pipeline Company ("Mojave")[collectively "El Paso"] hereby submit their joint comments on the OIR and the Phase I filings in response thereto by Southern California Gas Company ("SoCalGas"), San Diego Gas & Electric Company ("SDG&E"), Pacific Gas & Electric Company ("PG&E") and Southwest Gas Corporation ("SWG").

Summary

El Paso Corporation subsidiaries own and operate the largest natural gas transmission system in North America, and the EPNG system is one of the largest transporters of gas to California. In addition, the Mojave system supplies gas exclusively to industrial and other markets in California.

El Paso commends and supports the Commission's effort in the OIR. El Paso emphatically agrees that the Commission should act *now* to ensure reliable natural gas supplies to California at reasonable rates over the long term. El Paso also generally supports the proposals by the state's utilities to the effect that they be given pre-approval, subject to certain parameters, to enter into new or amended gas transportation contracts with the interstate pipeline companies. However, in light of the present, substantial uncertainties regarding the magnitude and timing of liquefied natural gas ("LNG") supplies, as well as overall gas market and production trends, El Paso urges the Commission to consider two central issues:

- whether the California gas utilities should be directed to obtain more interstate pipeline capacity than they propose to acquire (with appropriate cost recovery assurances), as cost-effective 'insurance' against potentially significant gas and electricity price swings and supply disruptions that would be detrimental to *all* California consumers; and
- whether the utilities should be directed to attempt to acquire a portfolio of contracts with staggered terms, using existing interstate capacity (of EPNG as well as other pipelines) that meets their supply diversity goals, before committing to higher risk, less flexible proposed expansions of interstate capacity.

Background

Supply

California's natural gas supply has historically come primarily from interstate pipelines connected to 4 major basins, as follows:

The **Permian basin** has several major interstate pipelines connected to it as well as a number of intrastate pipelines that provide more take-away capacity than the volume of production.[1] Producers have options to deliver their gas to markets in the producing area (primarily, Texas), or to have their gas transported to eastern markets or to western markets. California is only one option.. Due to the abundance of market opportunities that Permian producers enjoy, Permian gas has been historically priced, most of the time, at a premium to other basins. While Permian production has been in a period of gradual decline, the basin still produces an average of 5.0 Bcfd.

Gas from the **San Juan basin** has historically been priced at a discount to Permian supplies. As seen in **Attachment A**, there has been a significant increase in pipeline capacity serving the San Juan, and the trend is continuing. Recently, Transwestern Pipeline Company ("Transwestern") announced a planned expansion to the east from San Juan of approximately 350 to 600

[1] As discussed hereafter, this situation of multiple pipelines serving competing markets, which has historically characterized the Permian basin, is becoming the norm for other producing basins as well.

MDth/d. The expansion is slated to be in service by June 2005. If this expansion occurs, the San Juan basin will have additional export capacity and additional market options, raising local basin prices in relation to other supply basins. San Juan production is also in decline, but the basin still produces an average of 3.9 Bcfd.

The situation in **western Canada** has been historically typified by low commodity prices relative to other areas. The PG&E Gas Transmission – Northwest Corporation ("GTN") system provides the only major export capacity option for western Canadian gas to California. More recently, the Alliance pipeline has entered service, giving Canadian producers an option to export their gas east to Midcontinent markets. It was assumed, based on past experience, that production from western Canada would increase to fill the Alliance pipeline and that Alliance would eventually need to be expanded. That assumption has not proven true. As the Commission recognizes [OIR at 7-8], the latest production forecasts indicate a serious decline in western Canadian reserves.[2] Compounding this production decline, remaining supplies in western Canada often flow east to markets in the Midwest and Eastern United States when prices in those regions rise. This can be seen in **Attachment B**, which compares deliveries of western Canadian gas to California against New York gas prices. Back during the period when there were ample supplies, such as in 2000-2001, a price spike in New York had minimal or no effect on California deliveries. But more recently, as in the case in 2003 and again in January of this year, California deliveries drop dramatically when East Coast prices rise.

Volumes of gas transported by GTN were 300 MDth/d lower in 2003 than they were in 2002. The situation is continuing in 2004, and on certain days (e.g.,

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[2] For example, as reported in the February 9, 2004 issue of *Natural Gas Intelligence*, TransCanada recently testified before the Canadian National Energy Board (NEB) that its latest survey of production capacity across the Western Canada Sedimentary Basin generated bleak results. "There has been a shift from an era characterized by high inventory, readily-available prospects, low gas prices and quick supply response to one characterized by low inventory, higher supply cost, high gas prices and slower supply response." Since 2000, productivity has declined despite the 40,000 new gas wells. TransCanada also predicts that the Mackenzie Delta-arctic supply of 1 to 1.5 Bcf/d will fall short of the current decline in the western gas fields. It is anticipated that western Canadian output will drop by as much as 2.7 Bcf/d.

during portions of February and March, 2003) volumes are lower than historical average flows by up to 1.3 Bcf. [*See* **Attachment B**]. For these reasons, California markets will likely have to pay higher gas prices in order to compete vigorously for Canadian supply.

The **Rocky Mountain basin** currently produces an average of 7 Bcf/d. This area is marked by increasing production. In fact, the supply situation in the Rocky Mountain basin mirrors the situation in western Canada prior to 1992, when production increases quickly "chased" pipeline expansions. [*See* **Attachment C**]. But Rocky Mountain producers and markets have sought market optionality as well, and now most markets and local producers are interested in moving Rocky Mountain gas to the east.[3] This interest in eastern markets is driving a major pipeline expansion in the basin: fifteen shippers have signed long-term contracts for transportation service on the Cheyenne Plains Gas Pipeline Company, LLC ("Cheyenne Plains") system to transport Rocky Mountain gas to the east. Once placed in service (in late 2004 or early 2005), Cheyenne Plains will immediately provide another 560 MDth/d of eastward export capacity for Rocky Mountain gas, and a total of 730 MDth/d one year later, which should further narrow the basin differential with San Juan. There will be even more eastward capacity available to the Rockies if the 1.3 Bcf/d eastward expansion announced by Entrega Gas Pipeline (an affiliate Encana Oil & Gas USA) is constructed (planned to be in service at the end of 2005).[4] In other words, like the Permian basin (which has a number of pipelines serving a number of markets), the Rocky Mountain basin is experiencing – and will continue to

[3] The major export pipeline (Kern River) is viewed as one dimensional – i.e., one pipe from one part of the Rocky Mountain basin to one major market. On the supply side, the Kern River pipeline directly accesses gas from only the western portion of the Rocky Mountain basin. This position in the vast Rocky Mountain producing region means that Kern River does not have direct access to the prolific supplies in the Wind River, Powder River and Piceance basins in central and eastern Wyoming. For that gas to be transported from gathering systems to Kern River, it would need to be transported via another pipeline(s), such as the Wyoming Interstate Company, Ltd. ("WIC"), Overthrust Pipeline Company ("Overthrust") and/or the CIG systems.

[4] *Gas Daily* of February 27, 2004.

experience – an increasing number of market alternatives, resulting in narrowing or eliminating any price differential with prices in other basins.

California production has historically been another significant source of supply for the state. However, in-state production is now in steep decline. [*See* the data available on the California Department of Conservation's website at http://www.consrv.ca.gov/DOG/index.htm]. A proposed new major source of local supply is LNG re-gasification terminals to be built – at least initially – in the Baja of Mexico and perhaps Southern California or offshore. As discussed more fully below, however, there are enormous uncertainties surrounding the timing, feasibility, magnitude and reliability of LNG supplies for California.

Demand

Gas demand in California can be very volatile, due primarily to weather. Both snowpack/rainfall in California and in the Pacific Northwest (affecting hydroelectric generation) and local temperature are the principal drivers in demand fluctuation. For example, from 1985 to 2003, the maximum demand for gas used for utility electricity generation (UEG) varied from a high of 2,000 MDthd (in 2001) to a low of 800 MDthd (in 1996) [*see* **Attachment D-1**]. As that graph shows, when precipitation is high UEG demand is low and vice-versa.

Similarly, California's weather is quite variable. In the Los Angeles area, for example, within the last 13 years the temperature has ranged from a high of approximately 110° to a low of approximately 37° [*see* **Attachment D-2**].

In addition, there has been an upward secular trend in the volatility of gas demand driven by ever-greater increments of UEG serving the California market. If there is an usually dry or hot year, for example, gas demand peaks higher than in the past because so much more of the electricity need is met by burning gas. California Energy Commission Staff report in 02-IEP-01 (August 2003) at 1-2 (hereafter, "CEC Staff Report")]. These trends are the result of many factors, including environmental and geographic (e.g., siting) considerations. This upward secular trend in gas demand volatility is likely to continue, and will only serve to magnify the demand volatility arising from exogenous weather conditions.

Risk Management

The California utilities confront two major risk factors as they plan their interstate gas transportation needs over the coming decade: **geographic risk** and **timing risk**. The geographic risk arises from having an insufficiently diversified "portfolio" of access to the gas supply basins discussed above. Reliance on one or two supply basins puts California utilities and rate-payers at the mercy of local supply-demand conditions in any given basin, and it limits their flexibility to respond to dynamic market signals and lower-cost gas supply opportunities in other basins. California can procure "insurance" against this risk by requiring its utilities to buy and hold capacity on interstate pipelines serving as many supply basins as physically possible. This will enable California utilities to respond nimbly to dynamic market conditions and to minimize exposure to price risk in any one supply basin.

The timing risk arises from California utilities having effectively to "lock in" to any one supply basin over the often-lengthy duration of transportation service agreements on many interstate pipelines serving California. This risk is magnified due to the massive uncertainties associated with gas supplies from LNG.[5] For example, five years from now, California utilities will presumably know much more than they currently do about the availability and reliability of LNG supplies serving California markets. Long-term transportation agreements supporting expansions of interstate pipelines foist onto California consumers the risk of error in estimating how and when LNG will play out as a meaningful source of gas supply. California can effectively minimize this risk by entering into a portfolio mix of long and short-term transportation agreements using existing interstate capacity, with staggered expiration dates. This allows the utilities to preserve the option to add or subtract transportation capacity as more becomes

[5] For example, recently Marathon Oil Corp. announced that it is abandoning its LNG project in Baja and Calpine Corporation announced the withdrawal of its project at Humboldt Bay. And there is significant local opposition to the Long Beach and the Oxnard offshore LNG projects.

known about the contribution of LNG gas supplies to California's energy future. The bottom line is that California utilities should maximize the use of the existing interstate system in order to preserve their flexibility to respond to changing supply and market conditions in the coming years.

Comments

I. The volume of interstate capacity that the utilities propose to hold may be insufficient to achieve the Commission's goal of avoiding future shortages between natural gas demand and supply

The OIR makes it abundantly clear that the Commission's primary goal is to avoid future gas and electricity shortages, and the increased prices that result from such shortages:

> California's experience in the energy crisis revealed how a shortage of natural gas and/or electricity, whether real or contrived, can be devastating to the people, businesses and the economy of the State of California. Even a shortage in just a couple of months could cause billions of dollars of additional costs, which would not be incurred if there were a balance in the supply and demand...,[I]t is critical that California not face a shortage between its natural gas demand and supply in the future regardless of the cause of such a shortage. [OIR at 4-5, emphasis added.][6]

The OIR correctly recognizes that the costs of reserving interstate capacity are "insurance" against future price spikes [OIR at 17.] But the proposals of the utilities, if adopted, could compromise the Commission's goal of ensuring price stability because they would result in the utilities holding insufficient interstate capacity. This is true for two basic reasons:

a. SoCalGas, SDG&E and PG&E propose to use a planning standard that may be inadequate

The planning standards that are the bases of the SoCalGas, SDG&E and PG&E proposals may not sufficiently protect gas consumers from severe price

[6] The Commission has similarly recognized that a lack of adequate interstate pipeline capacity can have serious negative effects on the price and availability of electricity in California. *See* R.02-06-041 at 5.

spikes in the event of severe weather/market conditions. Those standards are as follows:

- **SoCalGas and SDG&E** – propose to use 80% to 110% of forecasted average temperature year daily core demand (non-winter months) and 90% to 120% of forecasted average temperature year daily core demand (winter months) [SoCalGas/SDG&E proposal at 16.]

- **PG&E** – currently uses a 1-in-3-year peak day standard; proposes to use a 1-in-10-year peak day standard, as well as a 1-in-10-year cold year winter standard, both for core usage only [PG&E proposal at 2-4.]

By contrast, SWG proposes to base its capacity needs on a peak day standard based on the coldest weather in 30 years. El Paso believes SWG's proposal – with assured cost recovery - is the appropriate standard.

The standards proposed by SoCalGas, SDG&E and PG&E could expose consumers to the risk of enormous additional commodity costs. The added commodity costs to consumers during just one winter could be many times the cost of the additional 'insurance' represented by the additional interstate capacity reservation charges. For example, PG&E points [PG&E proposal at 4] out that during the winter of 2000-01, it was forced to buy 400-500 MDth/d at Topock for core customers due to insufficient interstate capacity it held at that time (it held only 150 MDth/d on Transwestern).[7] The Commission has described California border prices at that time as being many times more than the price anywhere else in the nation [D. 02-07-037 at 6], resulting in PG&E's customers paying approximately $600 million in additional gas costs over just a few months.[8]

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[7] As PG&E notes [PG&E proposal at 3], if the utilities hold an inadequate amount of interstate pipeline capacity, not only is the risk of severe imbalance penalties for core customers increased but also non-core users are subject to greater risk of curtailment via diversion of their gas to serve the core.

[8] Had PG&E held sufficient transportation capacity on EPNG and/or Transwestern, it would have been able to receive gas into its system at a delivered price (weighted average) of approximately $6.96 per MMBtu (i.e., weighted average basin price plus transportation cost).This is far less than

PG&E's customers would have been far better off had PG&E maintained sufficient interstate capacity to cover all or most of this capacity requirement, even if PG&E had to pay for capacity it could not use during some years.[9] For example, EPNG's reservation charges for an additional 400-500 MDth/d of EPNG capacity at Topock during those same months (November 2000 through March 2001) were only $24.5 million. A more recent example of this situation occurred in the Northeast this winter. Gas prices soared above $70 per MMBtu when a cold snap hit the region and pipeline capacity became constrained.[10] Yet prices in the supply regions did not rise appreciably.[11]

Attachment E demonstrates this point in the form of a graph based on empirical data.[12] The graph shows the cost of 'insurance' (in the form of additional interstate pipeline capacity at various contract volume levels) plotted against the risks avoided (additional gas cost exposure of California utilities). This data shows that at any level of volume, the insurance premium is very low compared to the avoided commodity price risk.

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the weighted average price of $15.99 per MMBtu that it paid for purchases at the border during this period.

[9] Of course, a shipper such as PG&E can mitigate its cost of holding such capacity by releasing the capacity when not needed, as SoCalGas in particular, has been doing for some time with Commission approval. *See, e.g.*, "Compliance Report of Southern California Gas Company on the Acquisition of Turned Back Capacity in Compliance With Ordering Paragraph 1 Of Decision 02-07-037 and Section B.4 Of The Rules Appended to the Decision R.02-06-041" dated January 15, 2004.

[10] *Gas Daily* of January 15, 2004. Gas and electric consumers in New England are particularly vulnerable to such price spikes because a significant portion of the interstate capacity used to serve the utilities is interruptible. *See* "Staff Report of the Federal Energy Regulatory Commission" dated December 2003 in FERC Docket No. PL04-01-000, at 16-20 [reporting that 60% of the area's electric generation capability that is driven by gas only is supplied by only interruptible transportation on the interstate pipelines.]

[11] Henry Hub prices published by *Gas Daily* for period January 14-16, 2004, varied by only $.28 per MMBtu (i.e., from $5.73 to $6.02 per MMBtu.)

[12] The data reflected in the graph is based on the 2000 through 2003 time frame. The risk premium in the graph was calculated using the transportation costs on EPNG's system at the time, as if the shipper had contracted for an annual period versus the risk amount calculated by comparing the Topock border price to the El Paso San Juan delivered price and various incremental purchases per day.

The Commission has recognized system planning criteria that assumes a higher standard of reliability for core customers than the standard assumed by the utilities for reserving core capacity on interstate pipelines.[13] Yet, the OIR recognizes that the state now faces a dramatically different set of circumstances than in the past, when there were plentiful supplies available for purchase at the California border during periods of peak demand [*see, e.g.,* D.00-04-060 at mimeo 9] and the state enjoyed "close to one Bcf/d of excess interstate pipeline capacity <u>under firm interstate pipeline contracts</u> to California primary delivery points." [OIR at 15, emphasis added] The current environment of increasingly volatile demand, uncertain weather patterns,[14] a shrinking supply base, competition with markets in other states for gas supplies, competition for interstate pipeline capacity that serves California delivery points suggests the Commission should reject the planning standards proposed here by SoCalGas/SDG&E and PG&E. Moreover, the more conservative 1-in-30-year peak day standard is used by many major gas utilities across the United States, even those who (like SoCalGas) have substantial gas storage on system.[15]

Use of storage may not always make up for deficiencies arising from use of a riskier standard than the 1-in-30-year peak day standard. Non-core storage, which represents 55 Bcf (or 44%) of SoCalGas' storage capacity, is not under the

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[13] For purposes of system planning, the Commission adopted a criterion for the SoCalGas system of 1-in-35 for core service, including a 1-in-35 criterion for core customers for local transmission. However, while the Commission has seemingly recognized the benefits of sufficient intrastate pipeline capacity, it has failed to keep up with ensuring that the utilities have reserved sufficient interstate capacity for core customers. Thus, in D.00-04-0060 (2000), SoCalGas proposed increasing the core's interstate capacity reservations from 1044 MMcfd to 1076 MMcfd based upon a forecasted increase in the core's cold year demand forecast. The Commission failed to act upon this recommendation. Similarly, the Commission has failed to update PG&E's core reservations by adopting its Winter Firm Capacity Requirement. D.03-12-061 (December 2003).

[14] One reason a 30 year weather planning horizon is more appropriate is that gas demand is a function not only of the current weather for current use, but also a function of the weather from prior period's effects on water available for hydroelectric power generation. Since an unusually cold winter is not always preceded by a dry hydro year, one could miss that interaction on peak gas use if a shorted time horizon were used. And, as reflected on Attachment D-2, a longer planning period will capture more extreme weather peaks.

[15] Local distribution companies using the 1-in-30 standard include, for example, Peoples Energy (Chicago area LDC), Colorado Springs Utilities as well as SWG in Arizona and in California.

utilities' control. If the holders of that storage capacity do not manage their storage capacity appropriately, the resulting 'shortfall' must come from flowing supplies. [CEC Staff Report at 16]. If the non-core customers do not have an adequate amount of interstate pipeline capacity, California will confront even greater commodity price risk. As explained below, this increased demand on interstate supplies can deleteriously affect *core* customers as well as non-core.

b. The Commission should consider (in Phase II of this proceeding) requiring the utilities to hold the 'shortfall' capacity, if the non-core market does not contract for an adequate volume of interstate capacity

The OIR articulates the Commission's concern that an increase in California gas prices can have major consequences for the state's economy [OIR at 4-5]. In particular, a failure of non-core customers to contract for adequate interstate pipeline capacity can subject those customers to substantially higher gas costs, which can also have a collateral impact on core customers. Specifically, the utilities' core markets may not be protected from the risk of substantial electric price swings unless the utilities' capacity holdings include capacity for non-core shippers (to the extent that the non-core does not contract for an adequate volume of such capacity), with assured cost recovery. These price risk relationships between core and non-core customers and between gas costs and electricity derive from the already significant – and still increasing – amount of electricity generated by gas.

Also, California gas prices are a function of <u>total</u> gas demand and <u>total</u> available capacity, not just core demand and capacity held on behalf of the core. [See, e.g., CEC Staff Report at 11, 26]. The marketplace simply does not recognize the core/non-core distinction. Thus, in determining the total volume of interstate capacity that each utility should hold, the non-core market must be taken into account.[16] Indeed, the Commission should evaluate non-core

[16] None of the respondent utilities propose to hold capacity for non-core customers, on the basis that their mission is to protect the core (see the utilities' responses to the Commission's Data Request No. 3].

interstate capacity requirements and consider whether the state's utilities should hold, with assurances of cost recovery, any difference between those requirements and the volume of such capacity actually subscribed to by non-core customers. This capacity can be released by the utilities to non-core gas consumers during times of peak demand, thus helping mitigate the risk that the non-core will bid up the price of gas in a manner detrimental to all users, core and non-core.[17]

While El Paso recognizes this is an issue which the OIR reserves for Phase II of this proceeding [OIR at 29, ordering ¶8], the point bears mention here due to its close connection to the question of appropriate levels of interstate pipeline capacity to be held by the utilities for core service, as well its substantial nexus to the welfare of all California consumers in an increasingly unpredictable energy future.

II. Because the future is so uncertain, the Commission should consider rules which require the utilities to seek to acquire a portfolio of contracts for existing interstate capacity (on EPNG and as well as other pipelines), with staggered terms that meet the utilities' supply diversity goals.

The proposals by the state's utilities reflect their desire to maintain a diverse future supply portfolio, including the possible availability of gas from non-traditional sources such as LNG, Arctic gas, etc. The utilities also request Commission pre-approval for acquisition of interstate capacity that meets specified criteria. This request is rooted in the utilities' legitimate need for discretion to make fast-paced capacity decisions in response to rapidly changing market conditions – changes that often occur far too rapidly to accommodate the normal regulatory process. El Paso supports these efforts and stands ready to work with the utilities and the Commission to achieve these objectives. At the same time, in preparing its order in this proceeding, we urge the Commission to consider these critical points:

[17] Of course, how the Commission determines to allocate the costs of such capacity would be a separate issue.

a. **The utilities themselves should hold all of the capacity necessary to protect against significant price swings (to the extent, as described above, such capacity is not held by non-core users).**

The Commission has correctly recognized that California utilities must hold the necessary interstate capacity to serve at least their core markets, and therefore should not plan to make substantial spot market purchases or acquire capacity from others during periods of high demand. For example, in its opinion in D. 02-07-037 (2002), the Commission required the utilities to procure EPNG capacity with California delivery point rights that non-utility shippers offered to turn back to other shippers (including East of California shippers) as part of the Federal Energy Regulatory Commission's ("FERC's") capacity allocation proceeding on the EPNG system. There, and in the OIR preceding that opinion, the Commission pointedly stated:

> Marketers who plan to turn back California capacity on the El Paso system have no public service obligation to meet the needs of California consumers. Their willingness to turn back California capacity on the El Paso system is instead driven by profits and losses, including any potential short term financial losses without regard to potential long term profits. On the other hand, our Commission and the California utilities are responsible for ensuring that California consumers' natural gas and electric needs are met without risk of the substantial spike in natural gas prices and electric prices that occurred during winter 2000/2001.[Footnote omitted] [OIR in R.02-06-041 at 5].
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> The marketers turning back capacity and potential California replacement shippers are not subject to our jurisdiction, so we have no authority over those entities. Therefore, we proposed rules directing the California utilities subject to our regulation to sign up for as much of this turned back capacity as possible. D. 02-07-037 at 3.

Only if the necessary interstate capacity is controlled by the utilities can the Commission ensure its goals in this proceeding are achieved. Nor do the utilities' proposals appear to dispute this proposition (except to the extent they reject the proposition of holding capacity for the non-core).

b. **Existing or historic pricing differentials between supply basins (Canada, Rocky Mountains, San Juan and Permian) should not be rigidly used to guide future interstate capacity acquisitions.**

The proposal of SoCalGas, in particular, suggests that it is planning to acquire additional pipeline capacity accessing the Rocky Mountain production basin on the static assumption that the price of gas in that supply basin will continue to trade at a discount to other supply basins and sources. [SoCalGas proposal at 77 and 132]. Conversely, SoCalGas' filing suggests that it expects to reduce or eliminate its capacity from the Permian basin on the static assumption that Permian gas will continue to trade at a premium to gas from other basins and sources [SoCalGas proposal at 24 and 28]. Fundamentally, these assumptions overlook the dynamics of the marketplace. The utilities' proposals assume that past basin differentials will hold, and that market actors will not respond to the powerful price signals embedded in those differentials – namely, by expanding pipeline capacity serving supply basins with relatively low gas prices. They assume that the geographic dislocations that arise from insufficiently diverse export capacity in the San Juan and Rocky Mountain supply basins will continue.

<u>It would be a serious mistake for the California utilities to plan additional long-term capacity acquisitions on the assumption that past or current pricing differentials among basins will continue into the future</u>. On the contrary, everything we know about how energy markets operate and everything we know about current national energy policy favoring expansion of the national pipeline infrastructure strongly suggest that basin differentials, which are already small by historic standards [*see* **Attachments F, G and H**], will virtually collapse in the future. This differential collapse will likely be driven by construction of additional basin takeaway capacity in the low-cost supply basins.

This principle is illustrated most clearly in the May 2003 expansion of the Kern River system. Prior to that 900 MMcfd expansion being placed in service, as **Attachment H** shows, Rocky Mountain prices were substantially lower than San Juan basin prices. But that graph also shows that since the expansion went into service, San Juan and Rocky Mountain prices have been virtually equivalent (San Juan prices have averaged a mere 1.5 cents/MMBtu more than Rocky Mountain prices.) When the substantially higher cost of transporting gas on the Kern River system is factored in,[18] the cost of Rocky Mountain gas acquired in the basin and transported to the California border is now actually ***higher*** than the delivered cost of San Juan gas and comparable to the delivered cost of gas from the Permian basin. [*See* **Attachment I**]. Similarly, once the facilities of Cheyenne Plains are placed in service (in late 2004 or early 2005), there will be another 560 MDth/d of eastward export capacity for Rocky Mountain gas available immediately, and 730 MDth/d one year later. There will be even more capacity available out of that region (1.3 Bcf/d) if the Entrega eastward expansion project is constructed and/or if the proposed new Kern River expansion (of 500 MMcf/d) is constructed. It is reasonable to assume that basin differentials will narrow even further as these expansions take place. Indeed, with the construction of the substantial amount of new Rocky Mountain takeaway capacity, it is just as reasonable to assume that in the future San Juan prices will be *lower* than Rocky Mountain prices as it is to assume that San Juan prices will be higher than Rocky Mountain prices. With the new takeaway capacity, California will be forced to compete more aggressively with Midwestern markets for access to Rocky Mountain gas, thereby increasing the wellhead price of such gas, just as increased competition for Canadian gas from New York and other Eastern markets has increased Canadian wellhead prices and decreased the volume of Canadian gas flowing to California.[19]

Similarly, gas from the Permian basin, which was historically priced significantly higher than San Juan and Rocky Mountain gas, now averages only about 6.5 cents per Dth more than gas from those other basins [*see*

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[18] Kern River's maximum rate for firm service to the California border is $.6414, while the EPNG San Juan rate is $.326 and the rate on the Transwestern system is $.3820 (all rates are per Dth and stated on a 100% load factor basis).

[19] The Commission will recall that a similar phenomenon to that involving Kern River's 2003 expansion occurred as soon as the Alliance system went into service, i.e., Canadian gas prices were permanently higher.

Attachments F and G]. Indeed, due to the expected additional production to come from LNG facilities currently being constructed in the Gulf of Mexico and from additional drilling in the Midcontinent[20], the cost of gas from the Permian supply area could easily become more competitive with San Juan, Rocky Mountain and Canadian gas.[21]

The likely collapse in supply basin differentials illustrates principles of basic economics: as additional export capacity is constructed from a supply basin, gas prices rise. And as additional supply becomes available within a basin, holding export capacity equal, gas prices fall. Moreover, since <u>no one can accurately predict future price, supply and market trends over the long haul</u>, the most prudent, long-term planning approach for the California utilities is to: (1) acquire and maintain sufficient interstate capacity *from a diversity of supply basins available to them*; and (2) utilize existing interstate capacity *first*, before deciding to commit to higher-risk capacity expansions. This is particularly true since <u>the cost of transportation is only a small fraction of the delivered cost of gas to the consumer</u>.[22] Stated differently, the "premium" for interstate pipeline capacity "insurance" against commodity gas price spikes has never been more affordable, measured as a ratio of transportation costs to gas commodity prices. By contracting for a diverse portfolio of interstate capacity, with staggered terms,

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[20] *See Gas Daily* of March 15, 2004, article entitled "Old frontier: Producers returning to Midcontinent."

[21] There are three LNG receiving terminals (Cameron LNG, Port Pelican, and Excelerate Energy Bridge) in the Gulf Coast or Gulf of Mexico which have received their authorizations and are now moving towards construction in areas with extensive gathering, processing and transportation facilities. A fourth LNG project (Freeport LNG) is expected to receive its authorization within the next two months. The four projects combined would provide 3.3 Bcf/d (1.5, 0.8, 0.5, and 1.5 Bcf/d respectively) of base load vaporization capacity into Gulf Coast markets currently targeted by Permian basin supplies. In addition, there is an extensive expansion of the existing Lake Charles regasification terminal that would add another 1.2 Bcf/d to the facility's 0.63 baseload delivery rate. The current expansion at Lake Charles plus the four prospective projects could thus provide up to 4.5 Bcf/d of LNG supply to the Gulf Coast markets. This incremental supply would displace Permian basin production and could reduce Permian prices. In addition, there are eleven other proposed LNG receiving terminal projects that are moving through the development process that could further depress Permian Basin prices if brought to a successful conclusion.

[22] SoCalGas' proposal, for example, states (at 21) that the costs of holding interstate capacity are not a "dominant" component of core procurement costs. Figure 2 contained in that filing appears to show that transportation costs comprise only 1% of the delivered cost.

the utilities would increase their ability to respond to pricing differentials and – most importantly – would maintain supply security needed to protect against significant price spikes caused by periods of peak demand.

c. It would be unrealistic to assume that existing Permian basin or other EPNG capacity that the California utilities do not contract for (or recontract for) will not be needed again in the future or will always be available to California in the future.

SoCalGas as well as the other respondent utilities appear to assume (erroneously) that they will never need EPNG capacity sourced from the Permian basin, or that, if needed, such capacity will always be available to them. EPNG's southern system [identified on the diagram that is **Attachment J**] accesses the Permian basin. SoCalGas presently maintains 514 MMcfd (278 MMcfd of which is allocated to core) of EPNG capacity sourced from the Permian basin [SoCalGas proposal at 24]. PG&E maintains 105 MMcfd of EPNG capacity with Permian basin receipt rights. All of this capacity carries firm delivery rights at the California border.[23] Yet EPNG's southern system also serves growing markets upstream of California in New Mexico, Arizona and Mexico. As can be seen in **Attachment K**, for example, EPNG's southern system has been heavily used by shippers in those markets during periods when SoCalGas and other California shippers have elected to source their gas from elsewhere. If the California utilities do not recontract for their existing EPNG Permian capacity, FERC rules require EPNG to offer this capacity to other shippers.[24] Stated differently, if shippers are

[23] Since implementation of capacity rationalization on the EPNG system by the FERC in September of 2003, which remedied the problems under the former 'full requirements' contracts held by many East of California shippers, EPNG's California shippers have experienced reliable service with minimal curtailment (e.g., for maintenance).

[24] Similarly, in approving the Western Energy Settlement, the FERC specifically stated

> Absent such contracts, there is no Commission-enforceable certificate requirement that El Paso Pipeline serve particular customers or markets. If the Settling Parties intend to ensure that El Paso Pipeline reserves 3,290 Mcf/d of capacity for the California markets, then the Settling Parties or their agents must have contracts with El Paso Pipeline to reserve and schedule those volumes of firm mainline transmission and delivery point capacity. ... Reserving capacity through specific contracts is consistent with the

ready and willing to pay EPNG's maximum rates for capacity turned back by the California utilities, EPNG is required to sell it to them. In addition, EPNG may accept offers of less than the maximum rate. Thus, as the Commission similarly recognized in D. 02-07-037, capacity relinquished by California shippers may become permanently unavailable to California in the future.[25] This is particularly true in the case of Permian capacity. The Permian basin is a mature supply area with more than adequate pipeline export capacity. Given this situation, new capacity may not be constructed in the future to allow more Permian gas to flow to California.

Holding EPNG capacity, including Permian capacity, gives SoCalGas and the other utilities a flexible "tool" to manage their supplies. Such capacity imposes market discipline (through choice and alternatives) on the first-choice supply basins the utilities will seek to access. In addition to accessing San Juan and Permian gas supplies, EPNG's system can also reach Mid-Continent and Rockies supplies via upstream pipeline connections. In addition, utilizing largely existing infrastructure, California can have access on EPNG – at costs comparable to the Kern River pipeline[26] – to growing supplies in the Rockies *and* gain access to other non-traditional supply basins such as the Mid-continent by utilizing Cheyenne Plains and pipelines such as Northern Natural Gas Company

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Commission's policy that service should to those who value it most. 101 FERC ¶61,201 at 62,047-48 (2003).

[25] "[I]f no California replacement shipper acquires this turned back capacity, up to 725 MMcf/d of firm capacity on the El Paso system could be permanently lost to serve California customers. If there is a confluence of events, such as those that occurred in winter 2000/2001, the loss of 725 MMcf/d could have devastating impacts on both the supply and cost of gas and electricity for California customers." D. 02-07-037 at 3 [emphasis added].

[26] Transportation service from the Cheyenne Hub via Cheyenne Plains, utilizing the facilities of either Northern or Natural through EPNG's southern system to the California border could be accomplished for a total reservation rate of about $0.73/Dth. For transportation service via Kern River with access to the same sources of supplies (Powder River basin and other supplies that flow into the Cheyenne Hub), gas would first need to be transported across the WIC and Overthrust systems. Current reservation charges on WIC and Overthrust are $0.10/Dth and $0.07/Dth, respectively, resulting in a total rate via Kern River to the California border equal to $0.75/Dth from the Cheyenne Hub. While the cost of fuel using the Cheyenne Plains to EPNG route may be somewhat higher, fuel is only payable when the capacity is actually used. Thus, the 'insurance premium' represented by holding this very flexible capacity is no more expensive.

("Northern") and Natural Gas Pipeline Company of America ("Natural"). [*See the* diagram that is **Attachment J**]. These pipelines have interconnections with EPNG in the Permian basin. Currently, Northwest Pipeline Corporation and TransColorado Gas Transmission Company transport gas into EPNG's San Juan basin system at Ignacio and Blanco, respectively. Also, gas from Colorado Interstate Gas Company ("CIG") is received into EPNG's system at the Big Blue Meter Station. CIG's interstate pipeline system provides access to all of the major supply basins in the Rocky Mountain Region.

SoCalGas also suggests [SoCalGas proposal at 23-4] that it wants to reduce or eliminate EPNG Topock delivery capacity that, due to a FERC-required capacity reallocation, currently has off-system delivery points (PG&E-Topock and Mojave-Topock.) However, using the flexibility of the EPNG system, the Topock capacity can directly connect to the SoCalGas system. Recently, for example, EPNG was able to re-designate an annual average of approximately 60 MMcf/d of delivery point rights from PG&E-Topock to SoCalGas' system at Ehrenberg, thereby enhancing some of the capacity rights held to off-system points. EPNG is currently holding an open season through March 31, 2004, in which it is soliciting bids to allow existing shippers to re-designate delivery points to EPNG's southern system through the use of Mojave and the proposed Line 1903 at no additional rate. SoCalGas could participate in this open season and increase the value of its San Juan receipts that go to off-system points by re-designating these capacity rights to its existing system.

If the utilities decline to hold EPNG capacity now, it may be unavailable to California in the future. Given the Commission's overarching goal of promoting price stability and supply diversity/security, the Commission should consider requiring the utilities to continue to hold this capacity as a prudent hedge against an uncertain future.

d. EPNG is willing and able to make its capacity available now to the utilities on flexible terms, permitting the utilities to continue to provide service while awaiting development of LNG and other alternative supplies

A number of LNG terminals have been proposed in southern California and the Baja of Mexico. It is uncertain whether and to what extent LNG will be a viable source of future supply to California, and when LNG supplies will be available. Terminal projects face a number of significant political, environmental, regulatory, economic and other hurdles. In addition, LNG comes from a number of politically unstable foreign sources (*e.g.*, Indonesia and Libya), adding a layer of source-country risk on top of the daunting siting challenges facing LNG. And even if the planned terminals were constructed, California would have to compete for supply with markets on the Pacific Rim and elsewhere. Finally, experience demonstrates that output levels from LNG projects vary substantially from day to day . Of those terminals currently in operation in the United States, only one (Everetts) currently produces at anything close to a constant, predictable level. *See* **Attachments L-1, L-2, L-3, L-4 and L-5.**[27]

Similarly, gas from the Arctic faces significant hurdles and, even under the best assumptions, is at least 8 years away.

Under these uncertain circumstances, it makes enormous sense for the California utilities to maintain capacity on existing interstate pipelines until the future becomes clearer. As discussed above, EPNG's existing capacity to California, in particular, is a very flexible option available to the utilities and

[27] And the Everetts terminal is unique due to the large amount of LNG storage in New England that is critical for winter supply balance and the existence of a nearby electric generation facility. The region holds 46 storage tanks with a combined capacity of 15.1 Bcf [Northeast Gas Association, 2003 Statistical Guide, p.30]. The terminal supplies LNG to the storage facilities at a rate of 100 MMcf/d and this is a baseload delivery. [*See* "Staff Report of the Federal Energy Regulatory Commission" dated December 2003 in FERC Docket No. PL04-01-000, at 8.] Everett is also unique in that the nearby Mystic electric generation plant recently converted from oil-and-gas fired steam generation to combined cycle gas turbines (CCGTs). The plant is very well located in southern Boston and would be very difficult to replace on the electric grid. The new CCGTs are extremely efficient and gain a few extra percentage points of efficiency by using cold vaporized gas from the LNG facility instead of ambient temperature pipeline gas. The Mystic plant should therefore enter the electric dispatch queue at a very competitive level and should burn at a high utilization factor.

dovetails, as a function of time, with the LNG "learning curve." Indeed, EPNG's capacity provides access to the most diverse supply portfolio of any pipeline serving California. Stated differently, EPNG offers more inherent supply diversity per transportation dollar than perhaps any other pipeline system in North America. In addition to that *geographic* diversity, however, EPNG can help the California utilities mitigate their *timing* risk by offering transportation capacity for relatively shorter time horizons, and can assist the utilities in developing a portfolio of long and short term contracts, with staggered termination dates as sought by the utilities [*see* SoCalGas proposal at 27]. And where the contracts qualify for rights of first refusal under FERC regulations, this approach gives the utilities ultimate flexibility. It is certainly less risky and more customized than is the case with long-term contracts required to support new expansion projects. Equally important, it gives the California utilities the flexibility to respond to LNG opportunities, as more becomes known about LNG as a supply source for California.

Regardless, the utilities must be prepared to serve their ratepayers even if LNG and other future supply sources are not developed as currently anticipated. The Commission should therefore require the utilities to use all reasonable efforts to acquire existing capacity (of EPNG as well as other pipelines) as other non-traditional sources develop. This existing option to pursue acquisition of a portfolio of contracts with staggered terms, using existing interstate capacity that meets the utilities' supply diversity goals should be fully explored before the Commission permits the utilities to enter into contracts supporting expansions of interstate capacity.

e. The Commission should scrutinize carefully proposals by the utilities to enter into new contracts involving expansions of interstate facilities

El Paso generally agrees with the utilities' position regarding the need for preapproval of new contracts for interstate pipeline capacity. Those proposals would grant the utilities authority to enter certain contracts without any prior notice to or review by the Commission (e.g., contracts for terms of less than 3 years; contracts for volume less than a specified amount; etc.) Contracts not meeting these criteria would be subject to prior notice to and approval by the Commission under an expedited procedure.

However, the Commission should consider modifying the 'pregranted approval' criteria proposed by SoCalGas and SDG&E (and adopted by PG&E) with respect to contracts of any volume for new interstate pipeline capacity into the state. New interstate pipeline projects require expensive, long-term contract commitments (typically, 10 years or more) that may not be the best choice given the state's timing risk profile discussed above. Such long-term commitments place unnecessary risk onto California consumers in the current uncertain environment, given the other alternatives available to them. As **Attachment M** reflects, there is currently an adequate amount of interstate pipeline capacity available to California. Much of this capacity, including capacity offered for release on Kern River and EPNG, is available under contracts with shorter terms than 10 years. Under these circumstances, the utilities should not be authorized to enter into contracts supporting new interstate capacity expansions without prior Commission approval. Such contracts could limit the flexibility inherent in existing interstate capacity and potentially expose ratepayers to significantly higher gas prices, as they have the effect of locking in California's consumers to a gas supply/transportation arrangement that may prove uneconomic. For example, if the utilities subscribed to a new Kern River expansion, and Rocky Mountain gas became more costly than gas from other sources (including LNG), the utilities could be locked in to using this long-term capacity, unable to economically alter their purchase mix to take advantage of lower prices elsewhere. The North American gas market is becoming an increasingly interconnected network that is able to adjust rapidly and efficiently to changing supplies and markets. California risks losing the benefits of that increasingly networked infrastructure if it allows itself to be tied to a single supply basin, however attractive any supply basin pricing may be at the moment.

As explained above, the utilities have much better options available to them using existing capacity. If the utilities wish to diversify by holding more Kern River capacity, they can accomplish that diversity objective by acquiring, on a pre-approved basis, released capacity on Kern River at lower cost and with less term risk than subscribing for a new expansion that will simply add to the basin's export capacity, allowing prices to rise further in relation to other basins. If the utilities nevertheless wish to sign interstate expansion contracts, they should first be required to seek Commission approval for such contracts and explain why options to acquire existing capacity are inadequate to meet their objectives.

f. Comments on the utilities' proposals regarding their intrastate facilities

El Paso has consistently and strongly supported SoCalGas' efforts to implement a system of firm tradable rights on its 'backbone' transmission system, as SoCalGas again proposes to do as part of this proceeding (SoCalGas proposal at 105 ff.] Such a system is necessary to optimize the efficiency of the natural gas delivery system from the interstate pipelines to the utilities. At the Wheeler Ridge interconnection between the Mojave/Kern River common facilities and the SoCalGas backbone system, for example, the fact that there is no system of firm tradable rights has resulted in well-documented inefficiencies when the gas of shippers on the upstream (interstate) facilities is not 'matched' to a contract on SoCalGas' system.[28] While El Paso needs to understand fully the details regarding how such a system would be implemented, conceptually El Paso agrees that SoCalGas' proposal should be adopted.

El Paso also strongly supports SoCalGas' plan (which will be the subject of a Phase II proposal or separate filing) [SoCalGas proposal at 11-12] to implement an off-system delivery service. Such a service could expand the choices available to the utilities' customers as well as shippers on the interstate

[28] *See, e.g., Kern River Gas Transmission Company*, 98 FERC ¶61,205 (2002) at 61,715-17.

systems. It is a plan consonant with the profoundly important concepts of optionality, flexibility, and diversity that underlie El Paso's comments in these proceedings and that, El Paso respectfully submits, should guide California's long-term gas supply strategy and energy future.

IV. Conclusion

El Paso supports the Commission's efforts to establish policies and rules to ensure safe, reliable long-term supplies of natural gas to California. The transportation services provided by the El Paso pipeline systems are aligned with many of the goals of this proceeding. These goals include supply access diversity, access to new supply sources, and reliability of transportation service. For over a half-century, El Paso has partnered with California to deliver reliable and efficient gas supplies to the state's consumers. El Paso wants to build on on its historic partnership and now assist California as it shapes its long-term gas supply policy and destiny for the twenty-first century. Some of the California utilities' well-intentioned proposals, unfortunately, create the risk that an insufficient amount of capacity on El Paso's systems will be available to California during peak periods. While different arguments can made about the future of gas supplies, markets and prices, the inescapable fact is that no one really knows what the future holds. In light of this substantial uncertainty and the options available to the state by continuing its partnership with El Paso, El Paso's systems should remain an integral source of transportation service for California.

El Paso specifically recommends that the Commission consider adopting the guidelines and procedures proposed by the utilities, modified as follows:

1. The California gas utilities should acquire interstate pipeline capacity to serve their core markets based on the1-in-30-year peak day standard.
2. The utilities should acquire interstate capacity for the non-core market, with appropriate cost recovery assurances, to the extent that the non-core does not contract for an adequate volume of such capacity.

3. The utilities should be required to use all reasonable efforts to acquire a portfolio of contracts with staggered terms, using existing interstate capacity that meets their supply diversity goals.
4. The utilities should not be authorized to enter into contracts supporting new interstate capacity expansions without prior Commission approval, but instead should be required to seek Commission approval for such expansions and explain why options to acquire existing capacity are inadequate to meet California's energy needs.

Respectfully submitted,

By ______________________

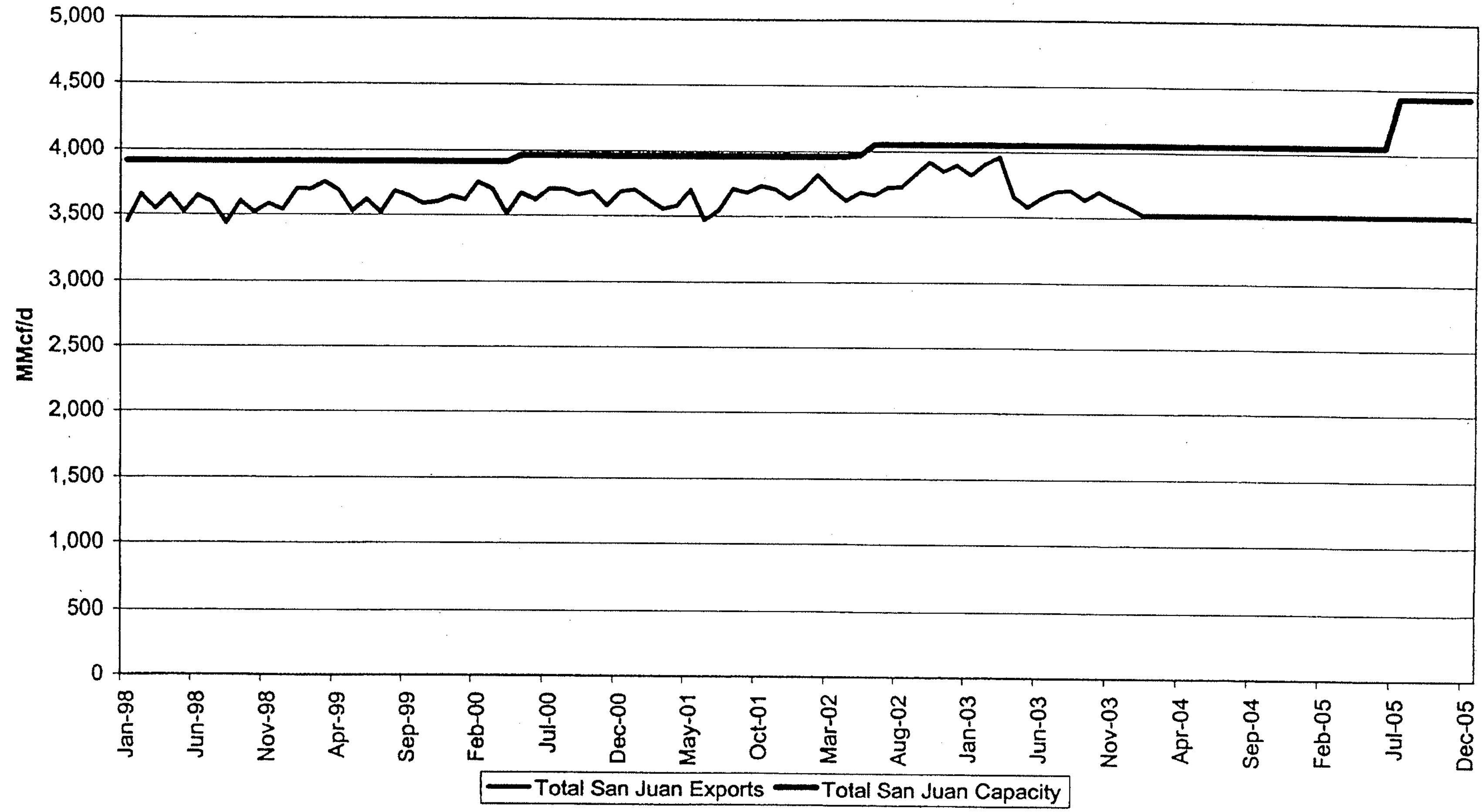
Craig V. Richardson, Esq.
Stephen G. Koerner, Esq.
El Paso Corporation – Western Pipelines
2 North Nevada Ave.
Colorado Springs, CO 80903
(719) 520-4443

Counsel for El Paso Natural Gas Company
and Mojave Pipeline Company

Dated: March 23, 2004

Attachment A

San Juan Basin Exports vs. San Juan Basin Capacity
January 1998 to January 2004
(San Juan Exports include Rockies Imports on NWP and TransColorado)

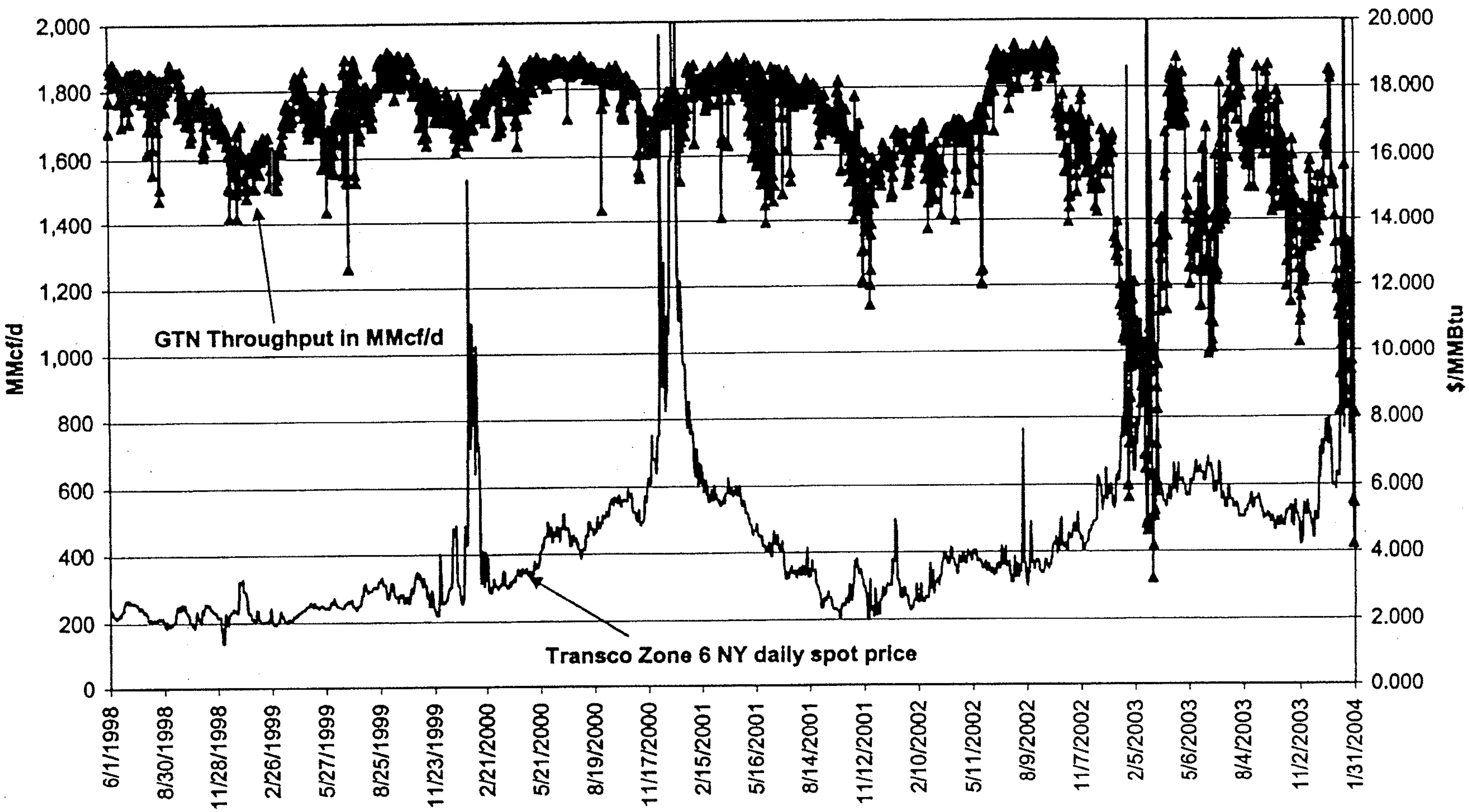


(Source: Lippman Consulting monthly flow and capacity reports)

Attachment B

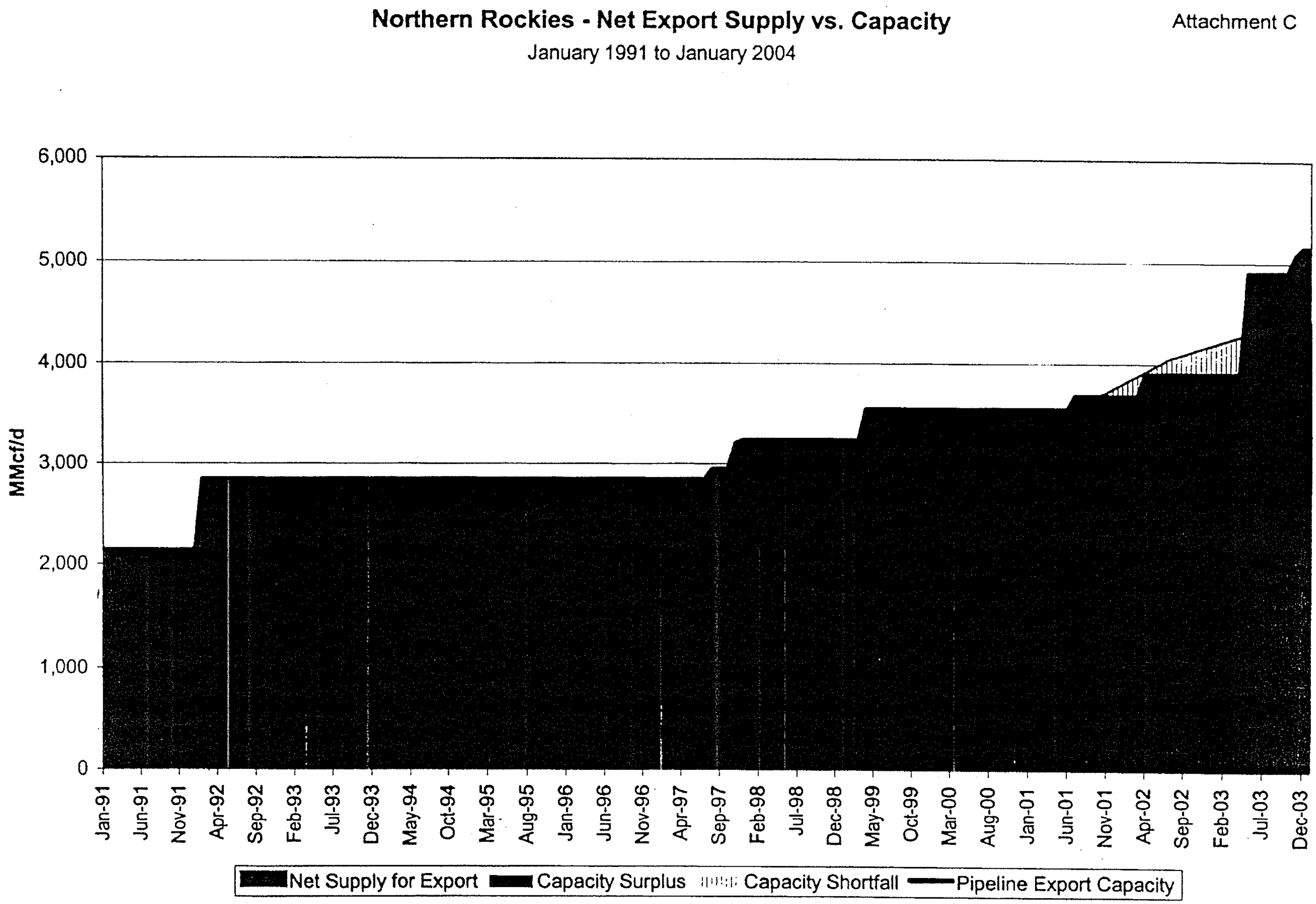
GTN Pipeline Deliveries to California by Day vs. Transco Zone 6 NY (NYC LDC's) Daily Price

June 1, 1998 to January 31, 2004



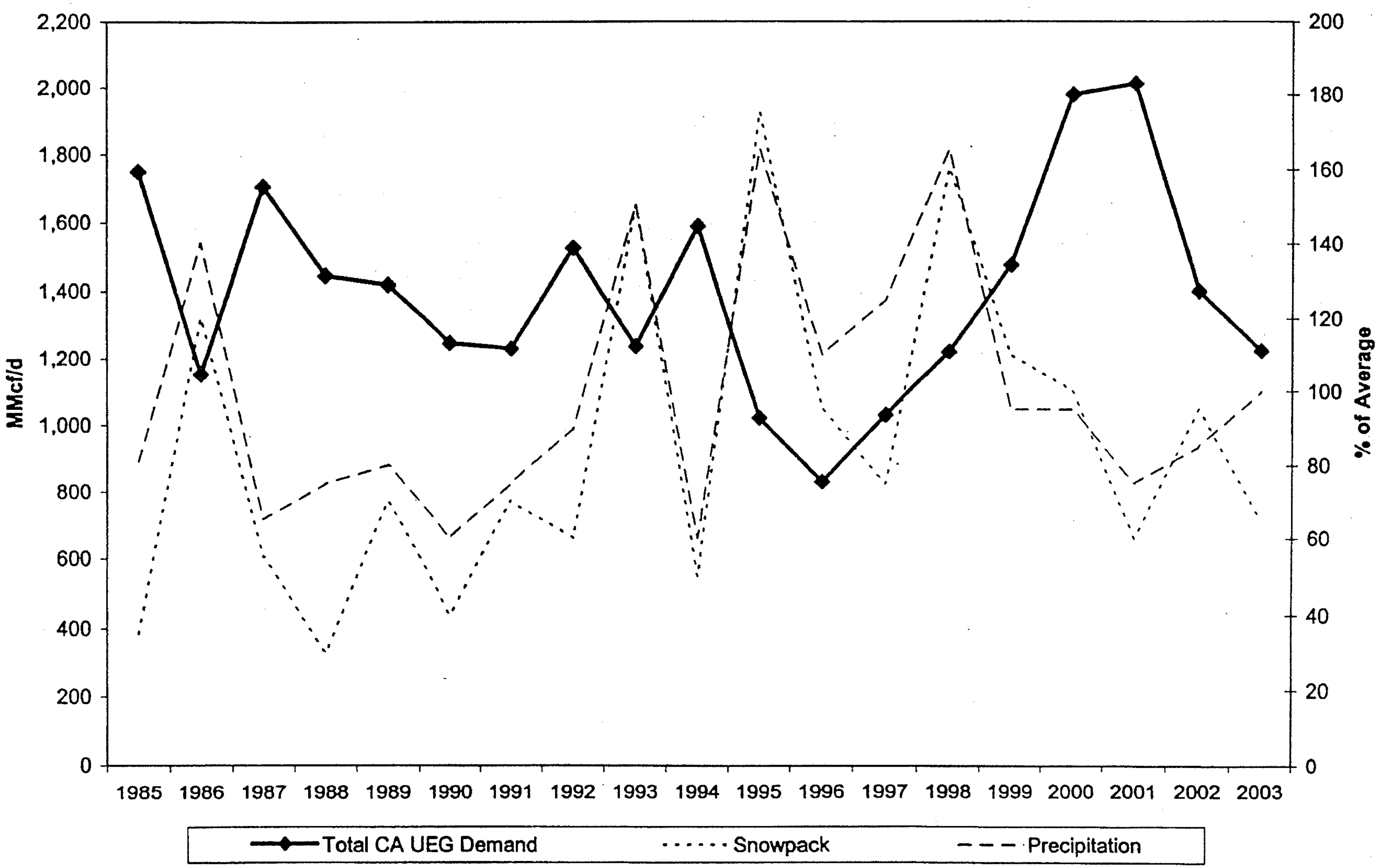
Source: Gas Daily's Midpoint Price

Attachment C



Attachment D - 1

Total California UEG Demand vs. Water Conditions

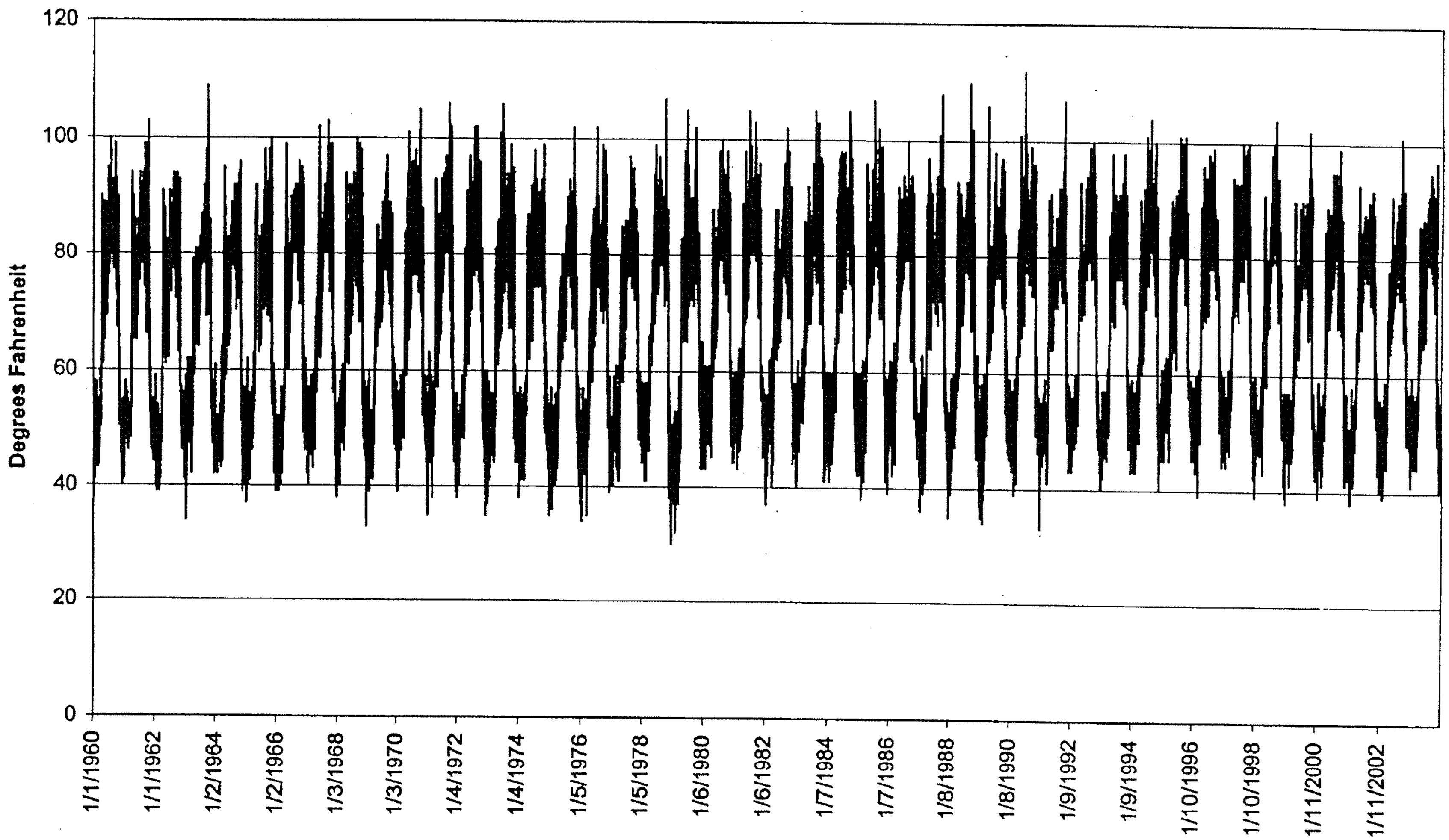


Attachment D - 2

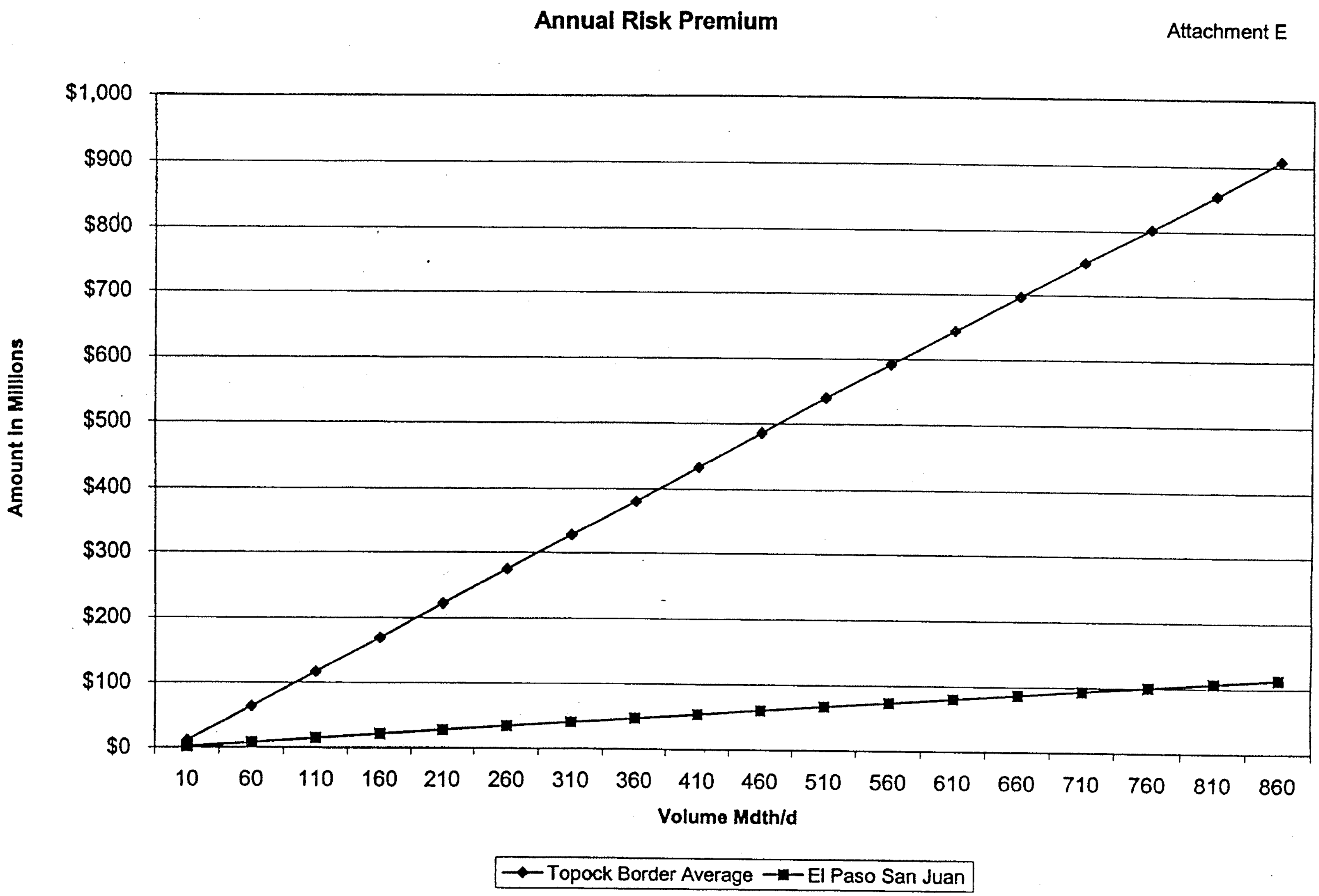
Los Angeles Summer High and Winter Low Temperatures

(Summer Months = April through October; Winter Months = November through March)

January 1, 1960 through December 31, 2003

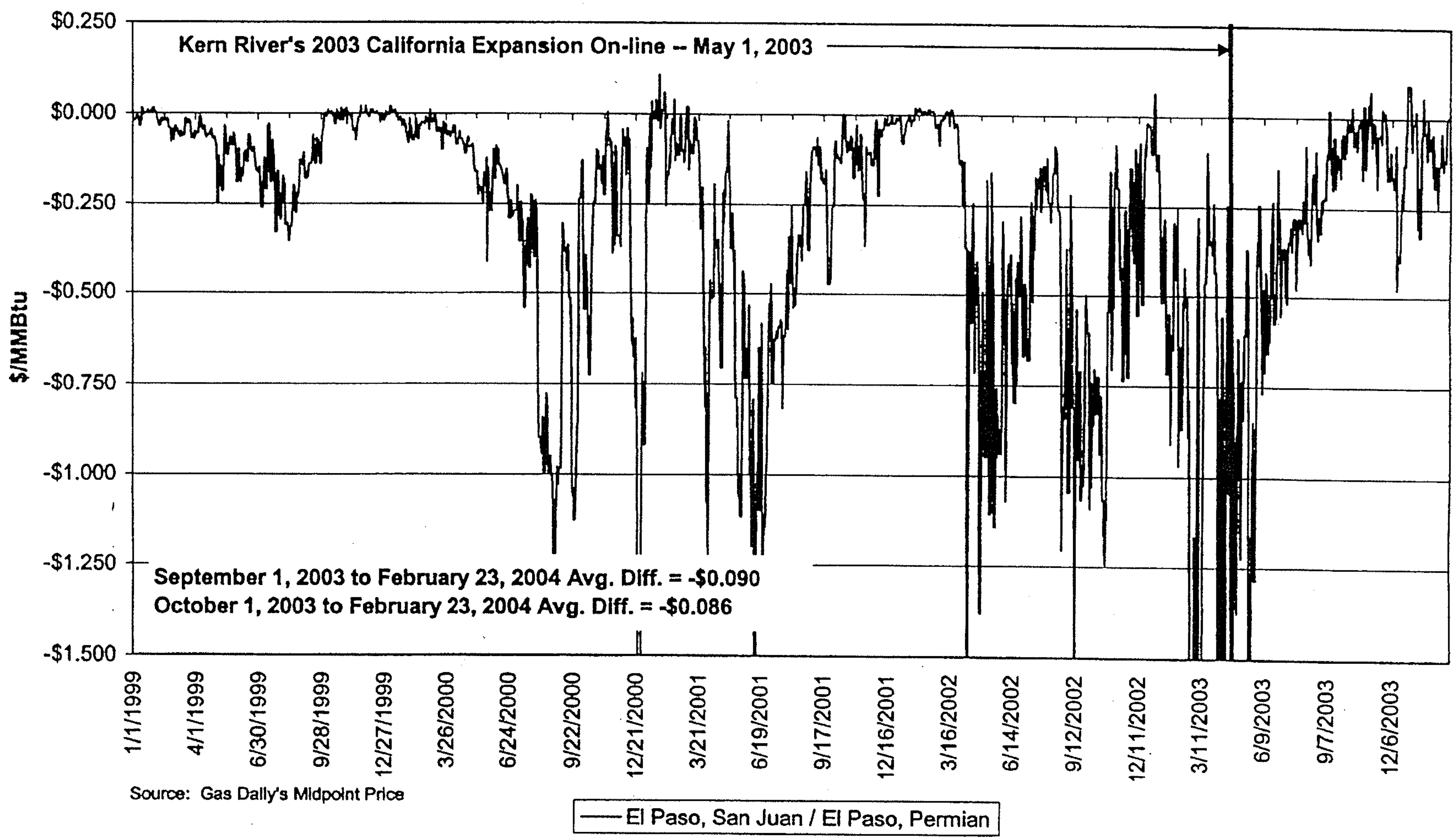


Attachment E



Attachment F

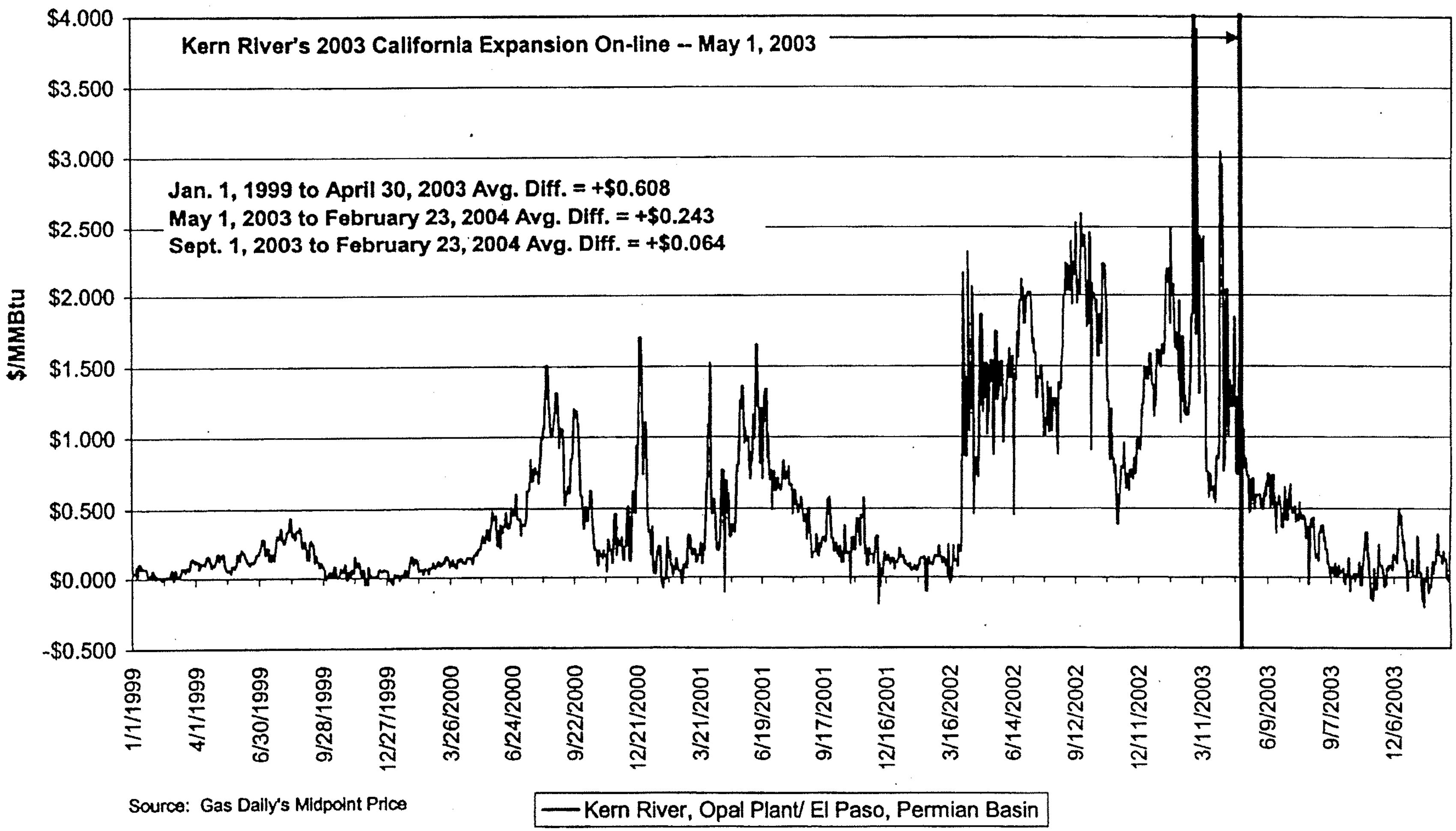
El Paso, San Juan Basin less
El Paso, Permian Basin Daily Spot Prices
January 1, 1999 to February 23, 2004



Source: Gas Daily's Midpoint Price

Attachment G

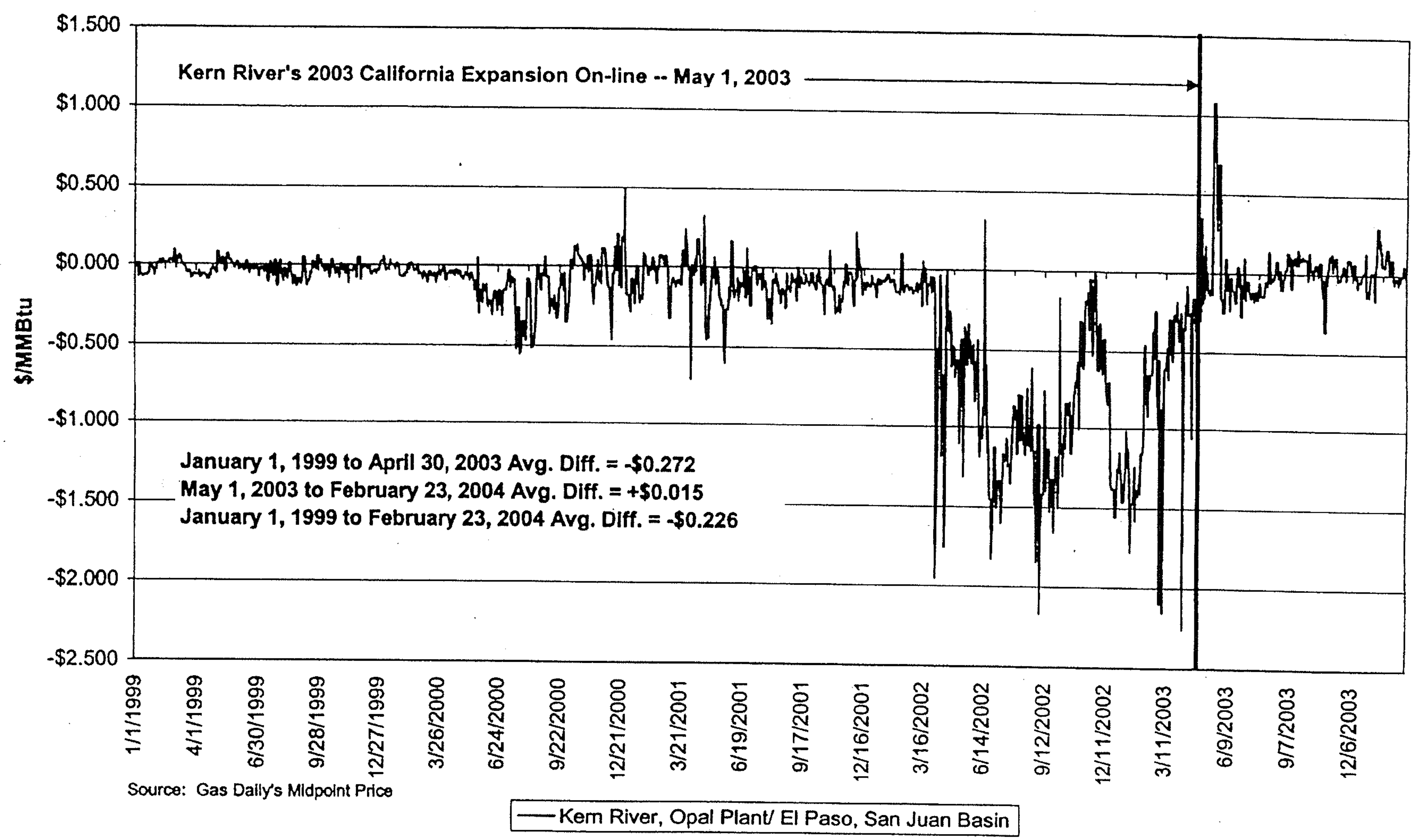
El Paso, Permian Basin less
Kern River, Opal Plant Daily Spot Prices
January 1, 1999 to February 23, 2004



Source: Gas Daily's Midpoint Price

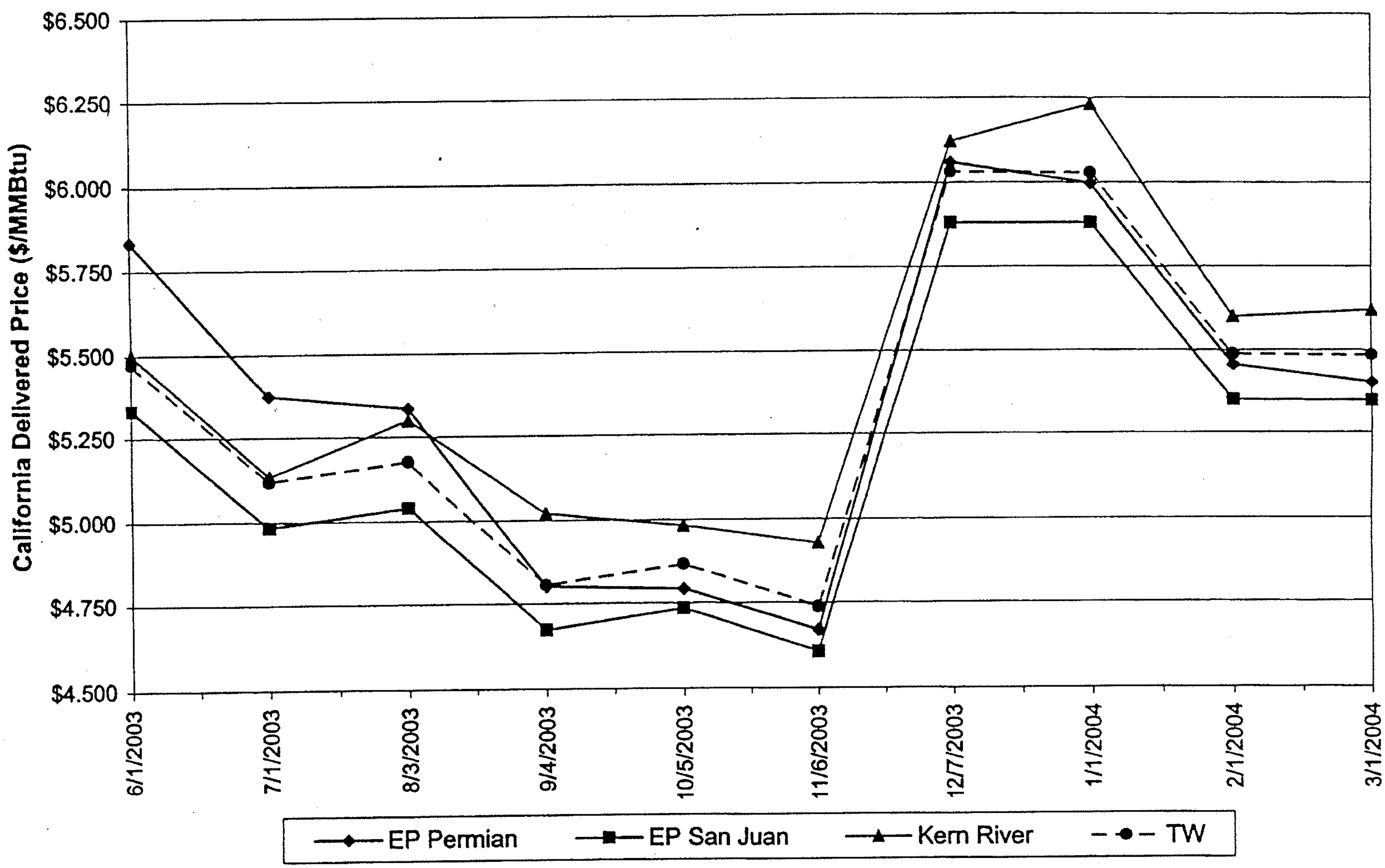
Attachment H

Kern River, Opal Plant less
El Paso, San Juan Basin Daily Spot Prices
January 1, 1999 to February 23, 2004



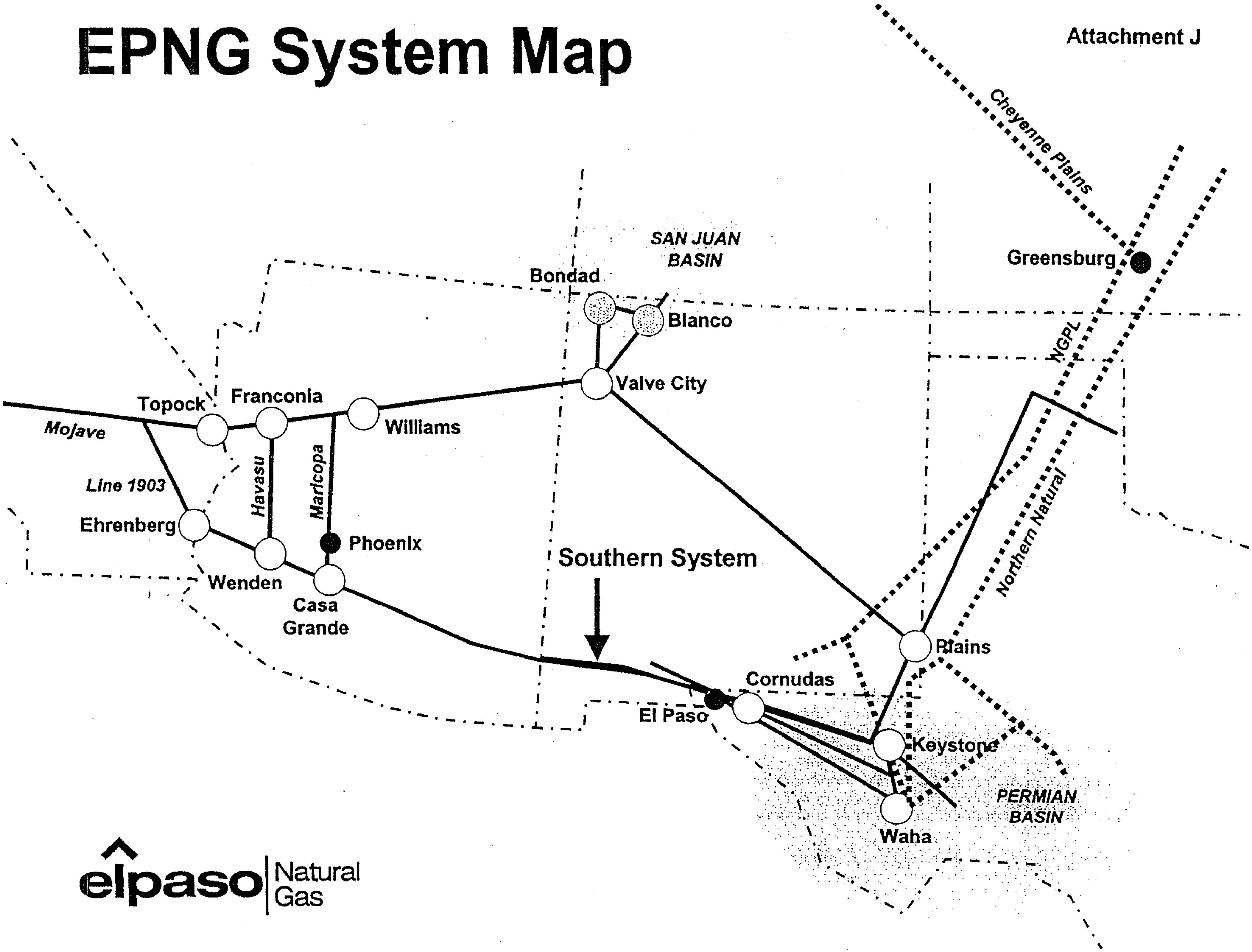
Attachment I

California Average Delivered Price After Kern River Expansion



Attachment J

EPNG System Map



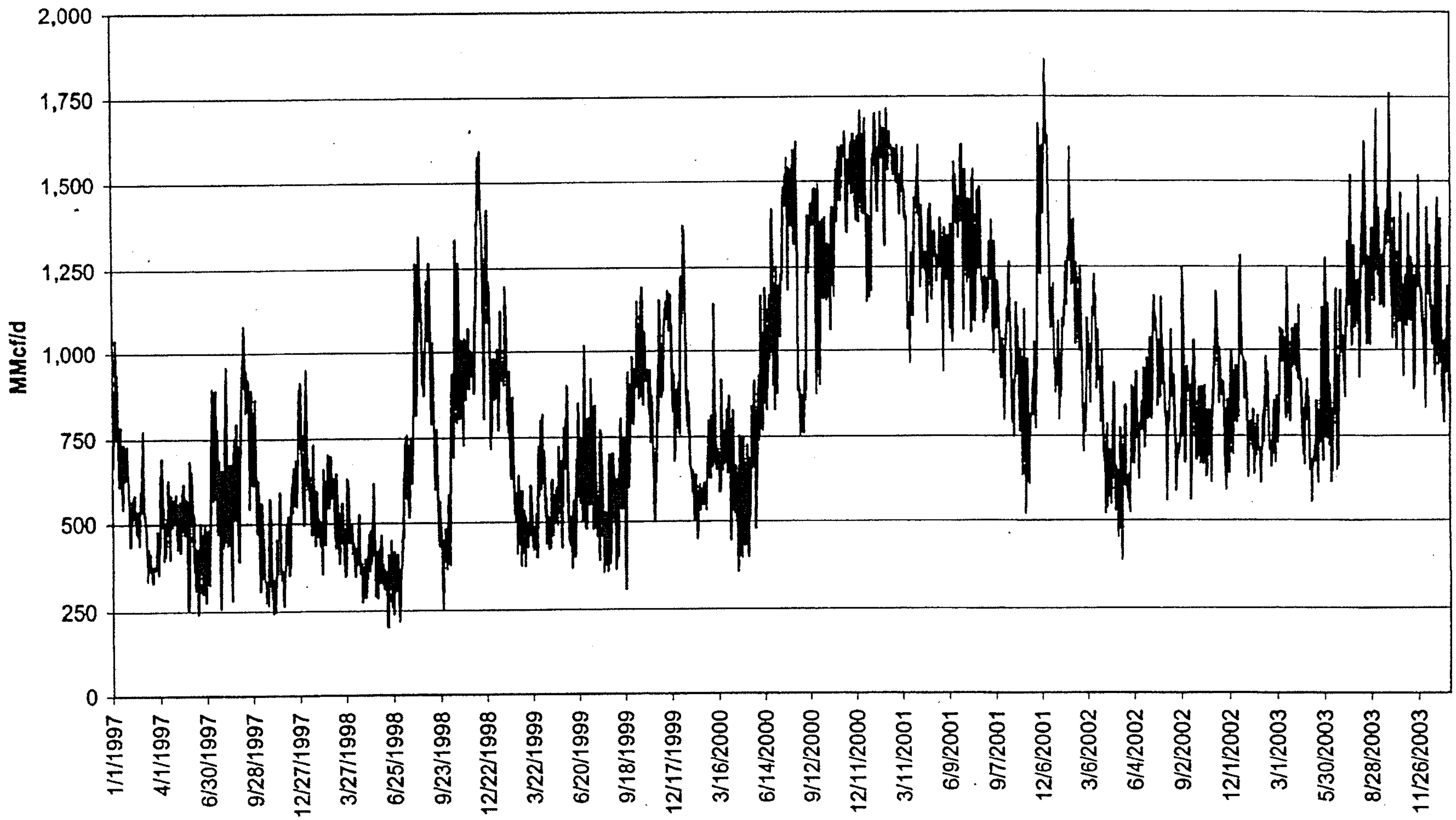
elpaso Natural Gas

Attachment K

EPNG's West Flows on the South System Mainline

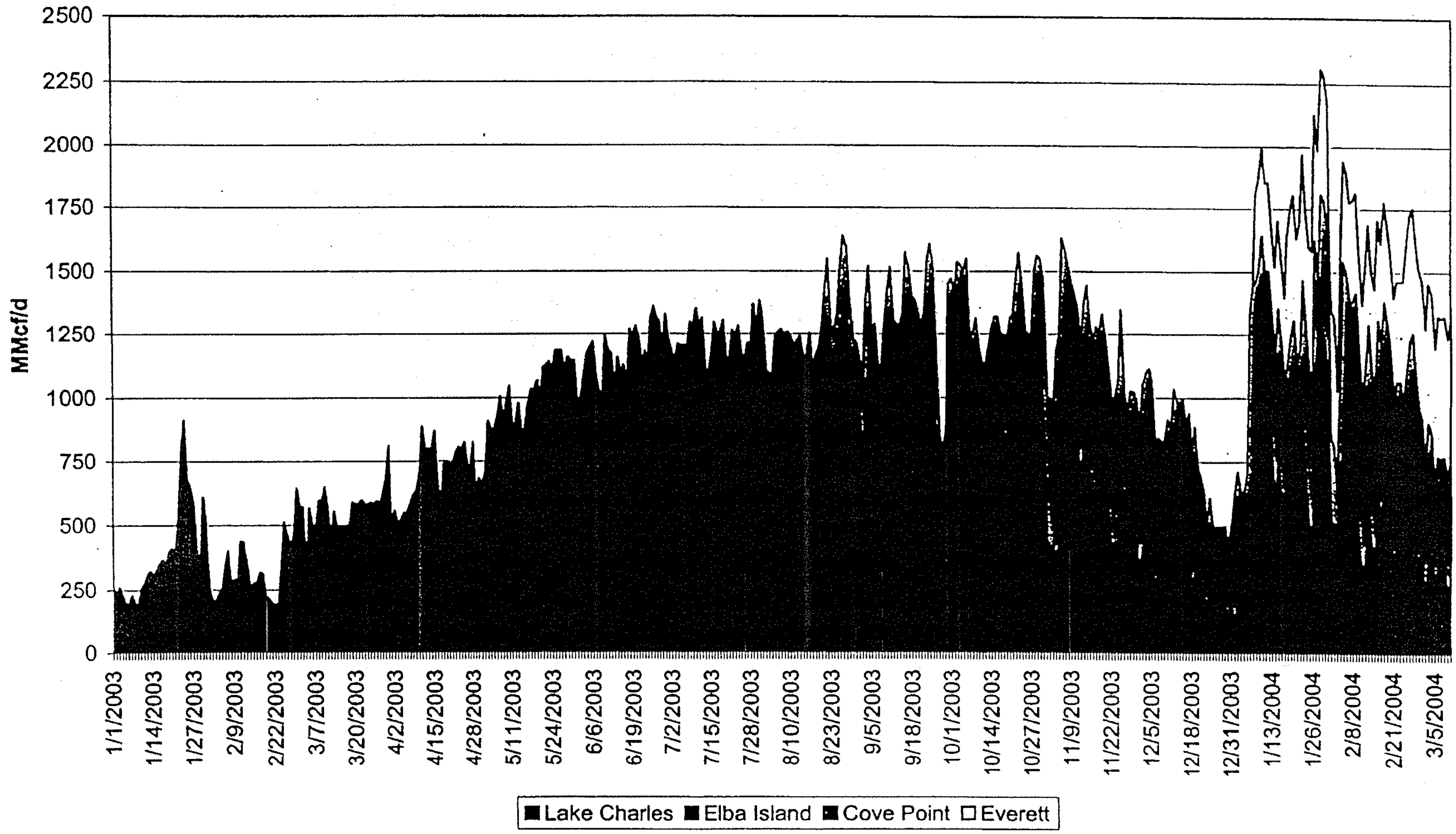
January 1, 1997 to January 23, 2004

MMcf/d

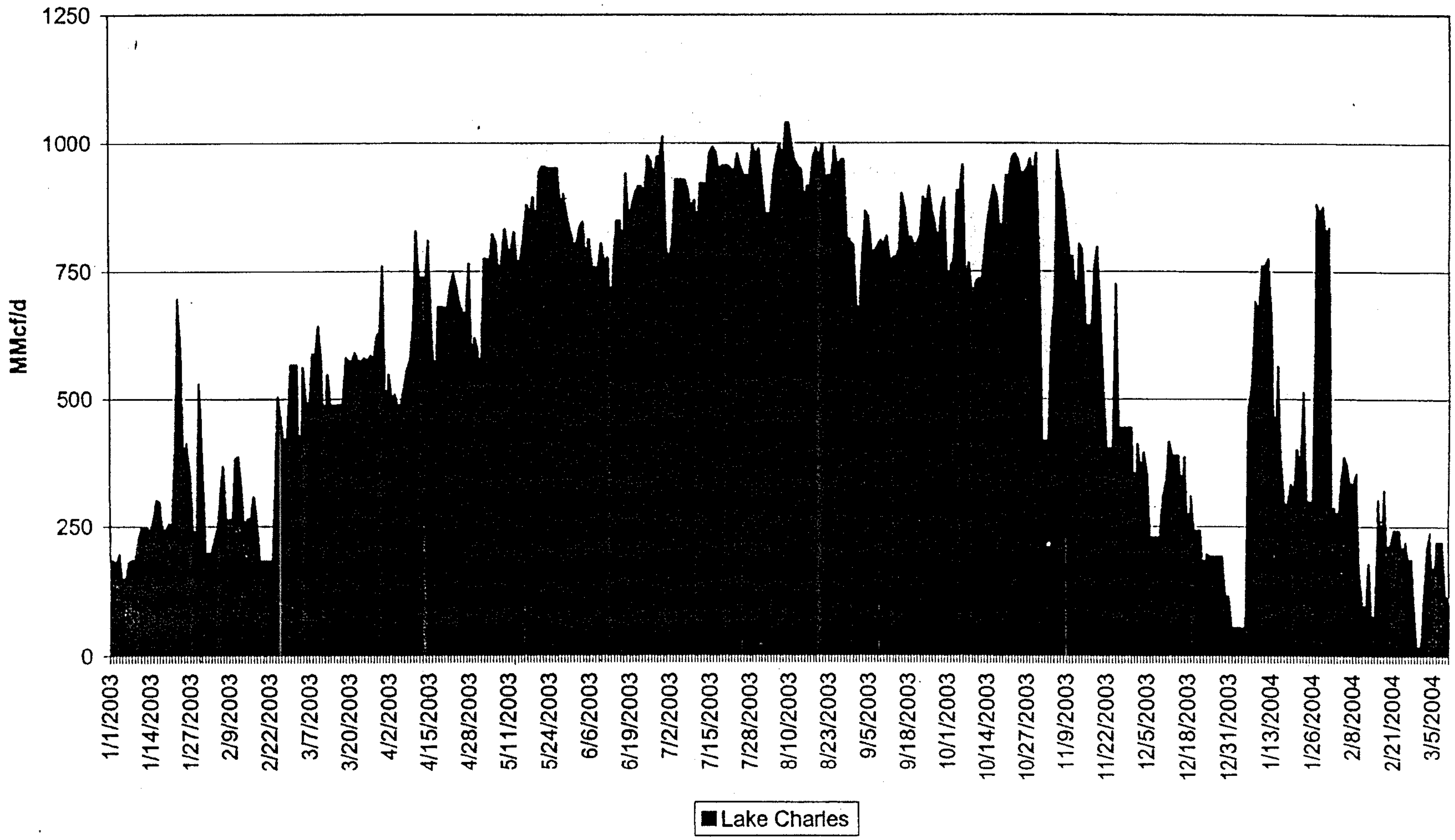


U.S. LNG Imports to Open Terminals by Day

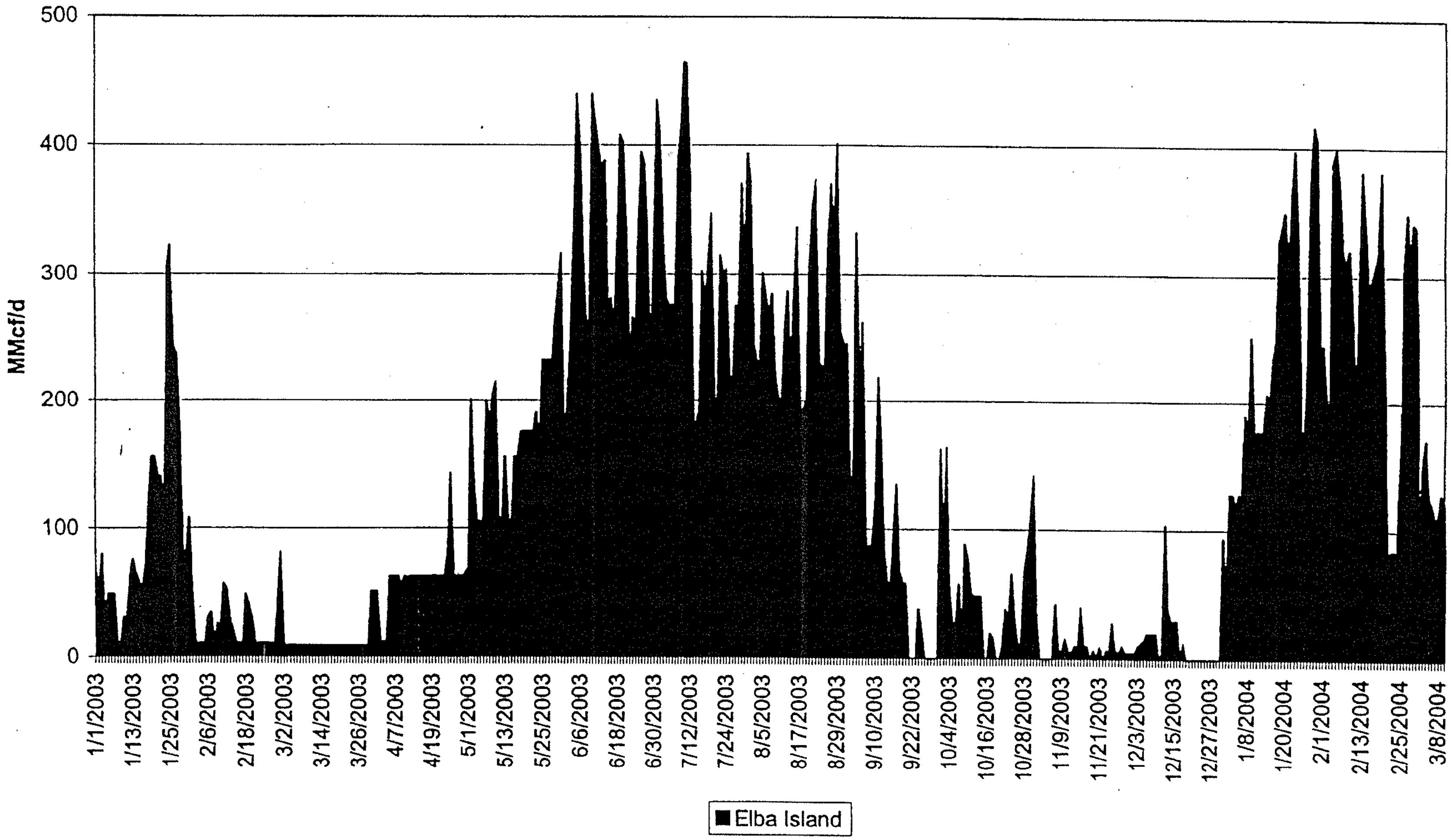
January 2003 to Present



Lake Charles LNG Imports
by Day
January 2003 to Present

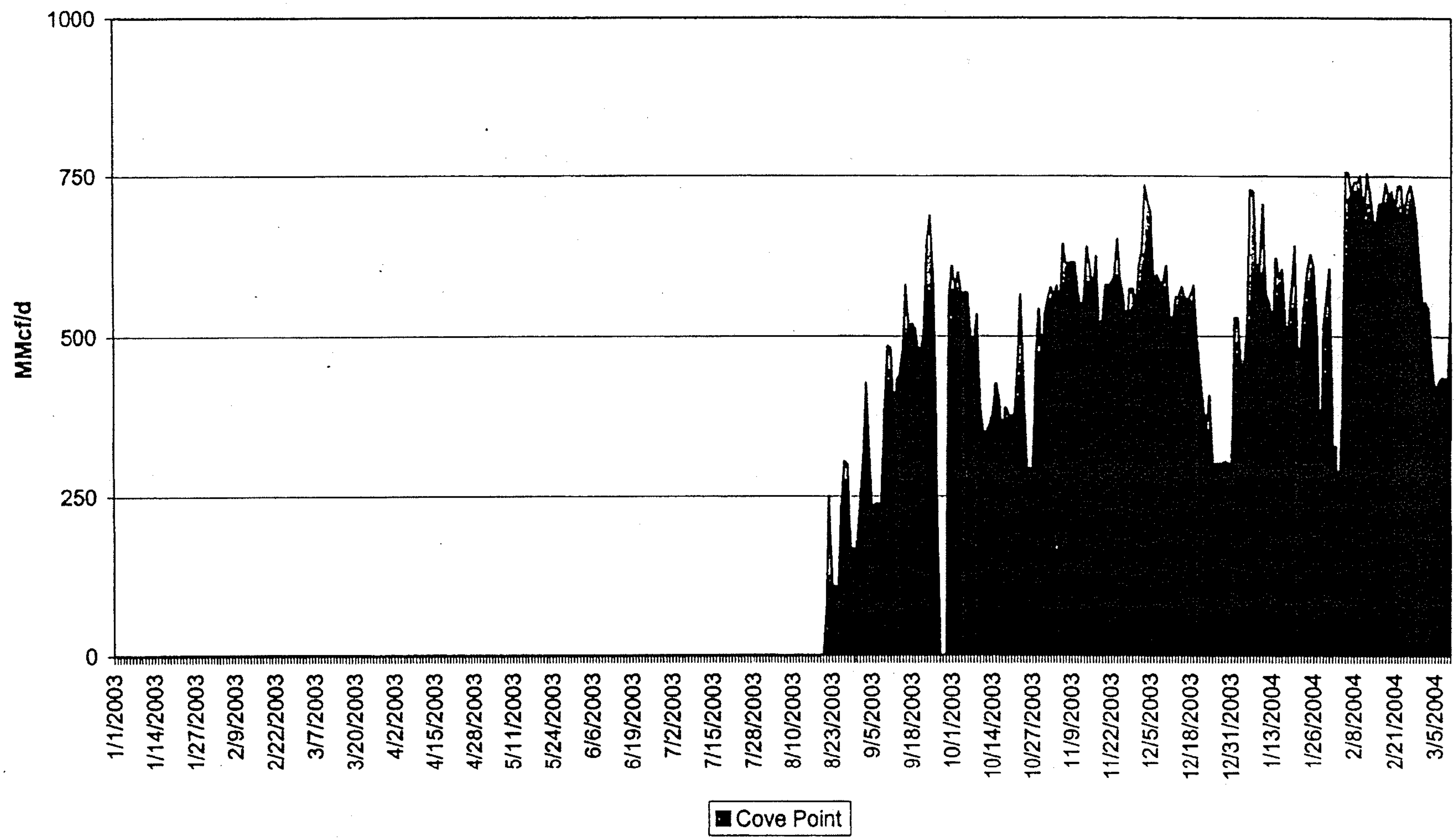


Elba Island LNG Imports
by Day
January 2003 to Present

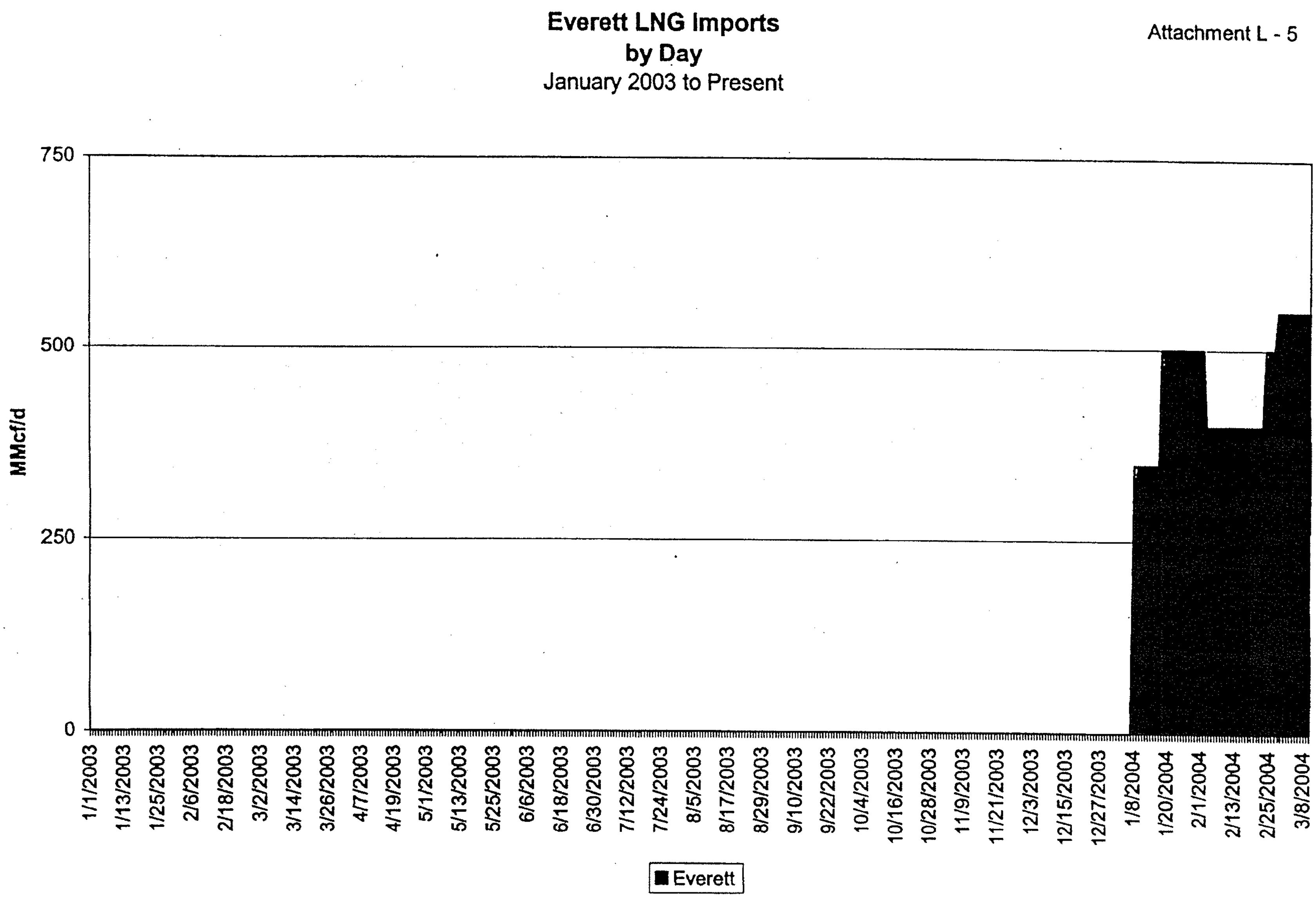


Attachment L - 4

Cove Point LNG Imports
by Day
January 2003 to Present



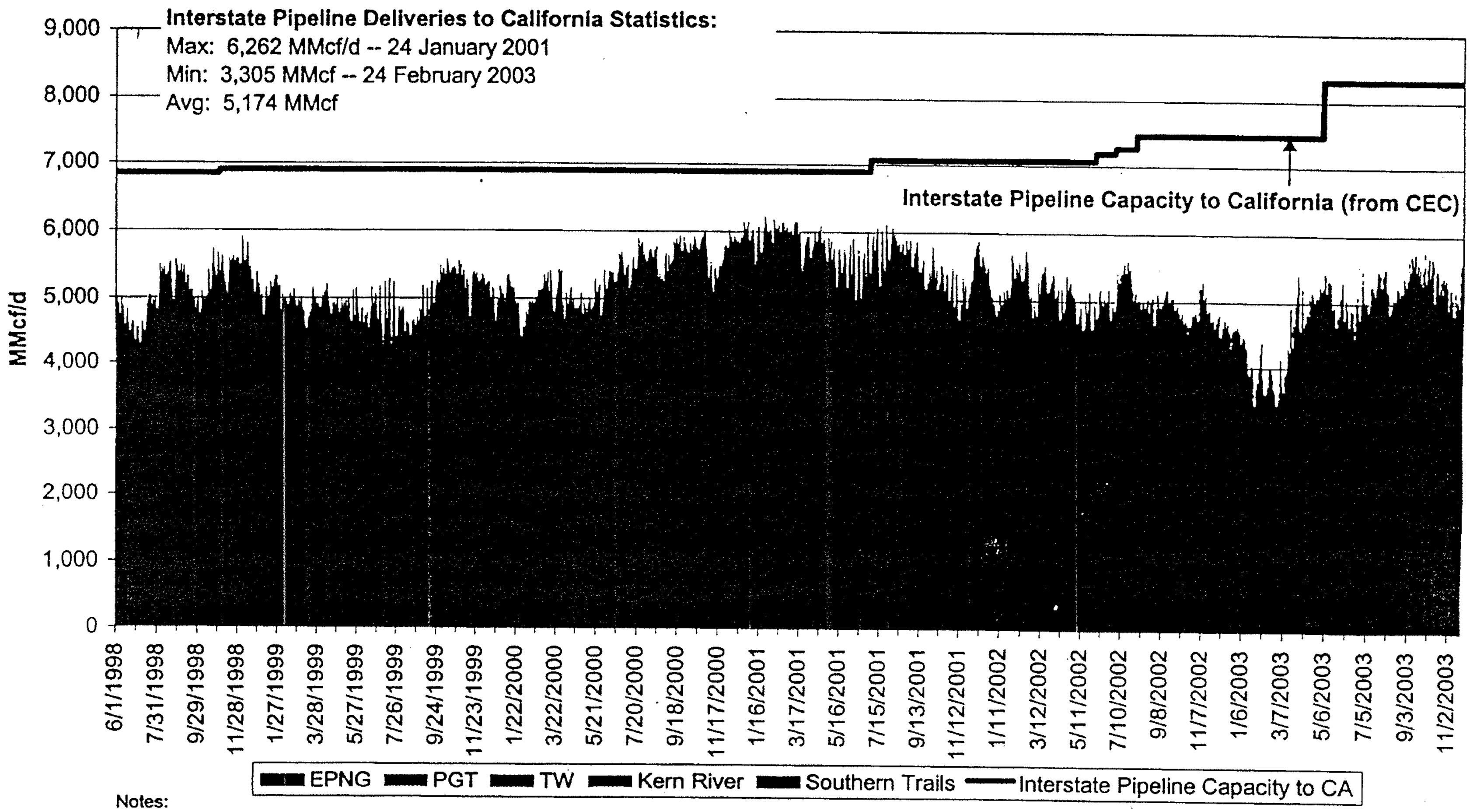
Attachment L - 5



Attachment M

Interstate Pipeline Deliveries to California by Day

1 June 1998 to 22 February 2004



Notes:

1) Capacity available to California can vary from CEC data depending on a variety of factors, including daily operating conditions (e.g., maintenance) and Office of Pipeline Safety requirements.

2) Throughput data is from pipeline web sites. Reported scheduled volumes may differ from actual volumes.

CERTIFICATE OF SERVICE

I, Alma J. Gilligan, certify that on March 18, 2004, I served a true copy of the **JOINT COMMENTS OF EL PASO NATURAL GAS COMPANY AND MOJAVE PIPELINE COMPANY** original attached document entitled by U.S. mail to the attached service list.

I declare under penalty of perjury under the laws of the State of California that the above is true and correct.

Dated: March 23, 2004, at Walnut Creek, California.

Alma J. Gilligan

Alma J. Gilligan

wc-87820

E-Mail Service List
R.04-01-025

jtisdale@arclightcapital.com
keith.mccrea@sablaw.com
johnj@bcjlaw.com
swilliams@desc.dla.mil
jimross@r-c-s-inc.com
agold@coral-energy.com
wgarrettesi@aol.com
sross@state.nm.us
roger.montgomery@swgas.com
lurick@sempra.com
mthorp@sempra.com
dgilmore@sempra.com
npedersen@hanmor.com
slehecka@hanmor.com
klatt@energyattorney.com
gloria.ing@sce.com
burkee@cts.com
jleslie@luce.com
lburdick@ferrisbritton.com
snelson@sempra.com
jkloberd@semprautilities.com
srahon@semprautilities.com
cscolastico@cc.sbcounty.gov
kpoole@adamsbroadwell.com
marcel@turn.org
freedman@turn.org
ek@a-klaw.com
rbm4@pge.com
epoole@adplaw.com
bcragg@gmssr.com
Jmctamaghan@steefel.com
jkarp@whitecase.com
lindseyhowdowning@dwt.com
mfogelman@steefel.com
mday@gmssr.com
frl3@pge.com
raveen_maan@city.palo-alto.ca.us
rochmanm@spurr.org
andy@skafflaw.com
aclark@calpine.com
joe.paul@dynegy.com
shilton@mofo.com
paulfenn@local.org
pjpowerlaw@aol.com
tomb@crossborderenergy.com
sberlin@mccarthylaw.com
chrism@mid.org
jeff@jbsenergy.com
matt@bradylawus.com